

# Electric Industry Deregulation:

A Look at the Experience of Four States



## Executive Summary

In the late 1990s, several states, including Michigan, began deregulating their electric utility markets in the hopes that competition in the generation and sale of electricity would drive down consumer prices. The enthusiasm for deregulation had waned in Michigan, 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 lessons or issues that might be relevant to the current discussion of Michigan's energy policy. PSC conducted case studies of Texas, Illinois, Montana, and New Jersey—four states that represent a range of geographies, political leadership, and deregulatory approaches and policy frameworks

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

- ◆ Rates have sometimes been more volatile under deregulation
- ◆ Electricity rates for industrial customers in one of the states declined in the early years of deregulation, but climbed again after initial power delivery contracts expired and wholesale prices increased
- ◆ 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
- ◆ A more flexible rate stabilization mechanism (such as Texas' "price to beat") during the transition period worked better than traditional price caps in attracting alternative providers
- ◆ 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
- ◆ 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<sup>1</sup>, 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 By the early to mid-2000s, some states had repealed electric choice laws or otherwise pulled back such efforts, while others stayed the course, hoping to capture the potential benefits of deregulation.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 we have 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 lawmakers have sought input on whether the state should revisit its market structure, including the 10 percent cap on electric customer choice instituted in 2008. As a backdrop, Governor 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 to review. PSC was asked by Consumers Energy and DTE Energy to review the experiences of a handful deregulated states to identify lessons or issues that might help inform the policy debate in Michigan. PSC chose Texas, Illinois, Montana, and New Jersey.

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<sup>1</sup> 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 four that represented different regions (South, Midwest, Mountain West, and East Coast), included a range of deregulation systems and policy frameworks, and reflected different political leaderships (Democratic and Republican). PSC recognizes this is just a subset of the varied and unique experiences of states that have deregulated their electric markets.

PSC conducted literature reviews of deregulation generally in the four states, reviewing primary and secondary documents on issues such as implementation approach, prices, electric provider switching rates, reliability, regulatory changes in each of the states, and other related deregulation issues. PSC also conducted interviews with state energy regulatory staff members in Texas and Illinois. The information from the review was evaluated in the context of national and other state trends on prices, generation mix, 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 issues and lessons among deregulated 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 market deregulation.



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

## Summary

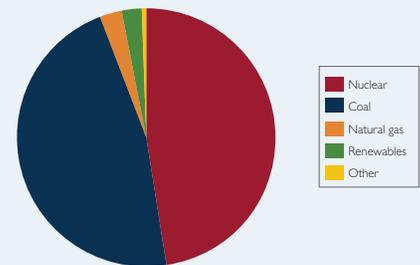
Illinois is an important state to review in the context of state experiments with electricity deregulation for two reasons. First, the deregulation process was protracted and highly controversial, and included years of legislative debate, as well as a high-profile complaint and intervention by the state 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 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
- ◆ Retail electricity sales (MWh): \$144,760,674 (#6 in nation)
- ◆ Average electricity price (cents/kWh in 2011): 8.97 (#26 in nation)

Generation by source (MWh)



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.<sup>1</sup>

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 nonexistent. 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 *Annual Baseline Assessment of Choice in Canada and the United States* (ABACCUS) report for 2012, 22% of residential customers, 81% of medium-sized non-residential customers, and 93% of large customers had switched.<sup>2</sup>

## 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.”<sup>3</sup> The IPA was created “in response to significant consumer electricity cost increases resulting from a utility-managed reverse auction process.”<sup>4</sup> 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.<sup>5</sup> The agency reported in 2011 that its procurement activities have resulted in \$1.64 billion in total savings for consumers since 2009.<sup>6</sup>

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.<sup>7</sup> In the first decade under deregulation in Illinois, participation by such customers was almost nonexistent. 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, 529 communities (including Chicago) had passed referendums for municipal aggregation.<sup>8</sup> 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.<sup>9</sup> 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),<sup>10</sup> 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?<sup>11</sup> 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.<sup>13</sup> 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.<sup>14</sup>

### 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 more than 100%

#### Ameren

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

markets and low commodity prices.<sup>15</sup> 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).<sup>16</sup> The Illinois Power Agency also purports to have played a key role in stabilizing prices.

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.

Illinois has seen electricity prices come down to around the national average—likely a function of the surplus capacity in wholesale

*“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<sup>12</sup>

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.<sup>17</sup>

## 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 of, 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. 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.

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# Endnotes

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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](http://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](http://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](http://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](http://www.icc.illinois.gov/electricity/switchingstatistics.aspx) (accessed 6-24-13). 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](http://www2.illinois.gov/ipa/documents/MunicipalAggregationMarchWebinarIPAPresentation3-12-12.pdf) (accessed 6-13-13).
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](http://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](http://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](http://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](http://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](http://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 was the case in 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.<sup>1</sup> 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 share of customers that had switched service from their incumbent provider was approximately 17.5%.<sup>2</sup> This participation rate, however, is still well below rates in other deregulated states.

- ◆ 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 (MWhs): \$79,179,427 (#20 in nation)
- ◆ Average electricity price (cents/kWh in 2011): 14.3 (#6 in nation)

## 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

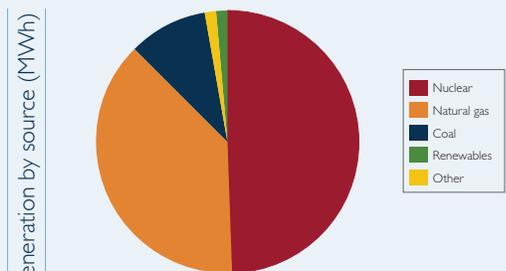
**2013**—PJM's Markets and Reliability Committee abandons effort to add a long-term capacity auction or alternative multi-year mechanism to the revised PJM charter

## 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.



SOURCE: EIA, *New Jersey Electricity Profile*, 2010.

New Jersey, unlike Michigan, is fairly dependent on energy imports, with more than 25% of its electricity bought on the wholesale market and transmitted to New Jersey from plants in other states.<sup>3</sup> 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.<sup>4</sup>

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.<sup>5</sup>*

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.

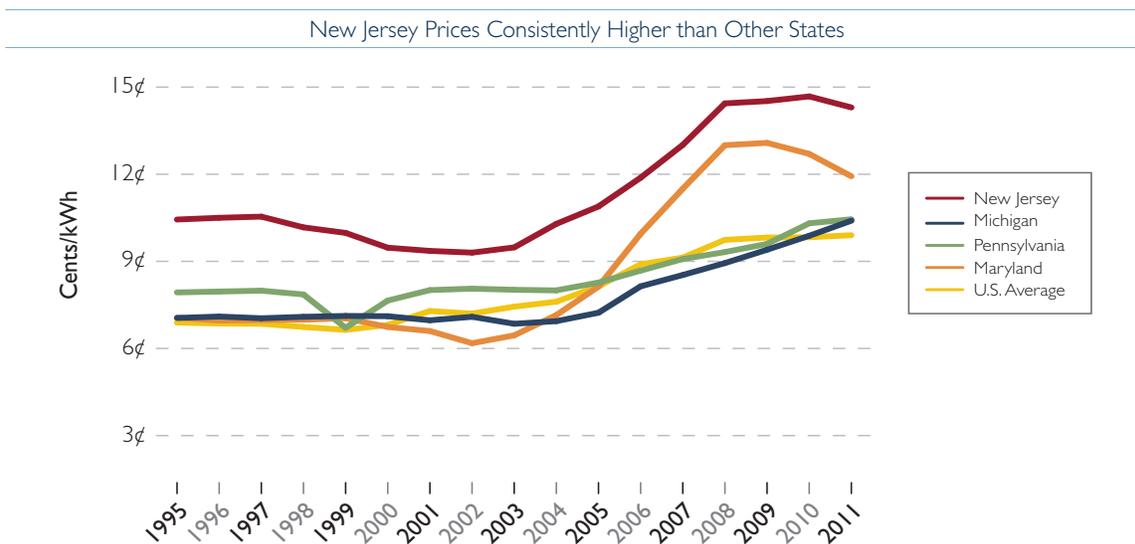
## Issues

### Affordability

New Jersey has historically had some of the highest electricity prices in the nation, consistently ranking 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 9.98 cents/kWh.<sup>6</sup>

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.<sup>7</sup> 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.



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 ca-

capacity prices to be locked in for only one year; therefore generators of new projects are unable to obtain financing at reasonable rates because of uncertain future revenue.<sup>8</sup>

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 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 more than \$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 more than half the electric generation facility deactivations since the last auction.<sup>9</sup>

## 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.<sup>10 11</sup>

## 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.<sup>12</sup>

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.<sup>13</sup> At the same time, incumbent PJM generators have filed suit in federal court challenging the constitutionality of LCAPP under the federal supremacy

*“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

## New Jersey Electricity Imports

25% to 35%  
over the last decade

clause.<sup>14</sup> 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 more than \$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.

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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.
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**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

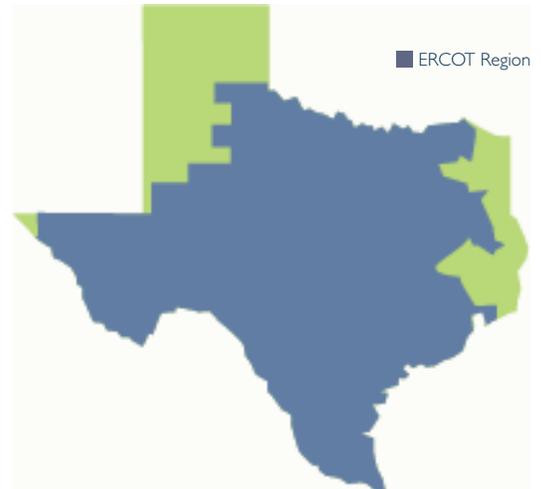
Texas is an important state to examine in the context of state deregulation of electricity markets, for a number of reasons. First, it was one of the earliest states to follow California in deregulating its electric industry—it began the effort in 1999 with the enactment of legislation for retail competition, 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.”<sup>1</sup> 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.<sup>2</sup>

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 FERC—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.<sup>3</sup> 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.

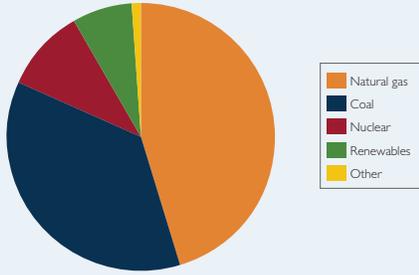
Texas relies on natural gas for the generation of electricity more than most other states, and this has influenced its wholesale and retail market design and performance under deregulation, as discussed further below.



## 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/](http://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)
- ◆ Retail electricity sales (MWh): \$358,457,550 (#1 in nation)
- ◆ Average electricity price (cents/kWh in 2011): 9.0 (#25 in nation)

### California Experience

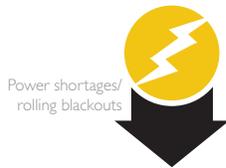
### Texas Response



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.

Texas had significant excess generation capacity and market conditions to support new generation.

Weather and environmental restrictions limited access to hydro-electric generation supplies in Pacific Northwest, contributing to California’s power shortages.

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.

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.

Poorly designed wholesale market allowed manipulation and excessive 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](http://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)

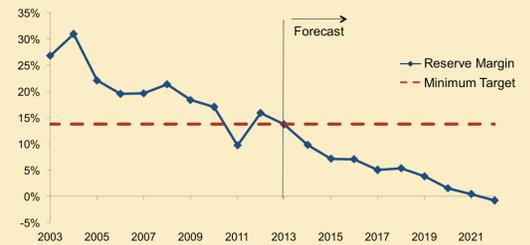
As with other areas of the country, Texas experienced a wave of new investment in the early 2000s, primarily natural gas plants. Investment losses followed, leaving investors more cautious and demanding more assurance that there will be stable revenues resulting from any new investments.<sup>4</sup> Meanwhile, the 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.<sup>5</sup> Investment had stalled despite reserve margins falling below target levels due to plant retirements and load growth.<sup>6</sup> A total of 15,223 MW of generation has been retired or mothballed since 1995 in ERCOT.<sup>7</sup> 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.<sup>8</sup> (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.”<sup>9</sup> 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.<sup>10</sup> It further concludes:

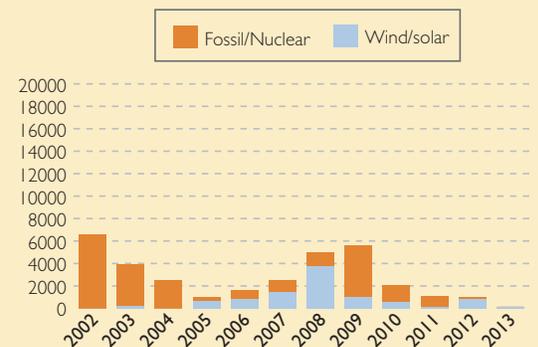
*The year 2014 poses a particular challenge because it may be approaching too quickly to add some types of new capacity, even if market conditions would support such investments.<sup>11</sup>*

### 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](http://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](http://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.<sup>12</sup> 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.**<sup>13</sup> 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.<sup>14</sup>

Texas' 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, led 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.*<sup>15</sup>

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.*<sup>16</sup>

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.”<sup>17</sup>*

—Public Utility Commission of Texas

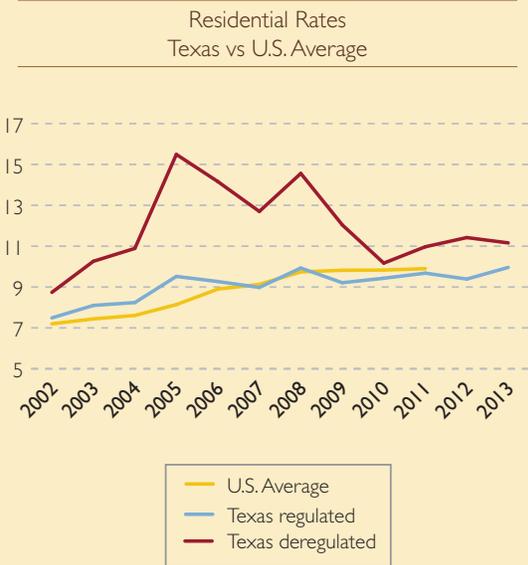
This volatility is a function of deregulation. Regulated utilities pass through fuel costs without a markup. This includes the utility's actual costs based on its fleet of power plants (typically a mix of nuclear, coal, and natural gas). Although these costs and the amounts charged to customers can fluctuate 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 providers.



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.

- ◆ 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 more than \$6.5 billion. By the time the issue was fully litigated, the total amount customers will pay amounted to more than **\$9.5 billion**.<sup>18</sup> 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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# MONTANA

**Dissatisfaction with the results of its deregulation law has led Montana to reverse course.**

**The state is now in the process of returning to the more traditional fully regulated utility model, which includes ownership of generation.**

## Summary

Montana is a potent example of what can go wrong when a state decides to deregulate its electricity market. The Treasure State enacted deregulation legislation in April 1997 with little public—or even legislative—debate about the potential effects. Montana also pursued deregulation in spite of the fact that it—along with many of its neighbors—enjoyed relatively low electricity rates because of cheap hydroelectric power and ample coal resources. The subsequent sale of its hydro assets to a Pennsylvania-based company, the bankruptcy of a telecommunications company formed with the proceeds of that sale, and price increases due to volatile wholesale electric markets led to years of political battles that included a failed ballot initiative and several attempts at corrective legislation.

The state has now come full circle and is in the process of returning to the traditional utility model in which generation, transmission, and distribution assets are owned by a privately held utility whose rates are regulated by state government.

## History and Profile

The deregulation story in Montana began in April 1997 (California had enacted its deregulation law in the fall of 1996), when then-Governor Marc Racicot signed the Electric Utility Industry Restructuring and Customer Choice Act (EUIRCCA). Although Montana, along with most of the states in the Mountain West, had relatively low electric prices due to abundant and inexpensive hydroelectric and coal resources, the argument was made that competition would reduce electric prices even further.<sup>1</sup> Supporters of the legislation included the chairman of the private, investor-owned Montana Power Company (MPC), the state's major utility, as well as a number of large, energy-intensive industries such as Montana Resources, a large copper smelting firm. MPC was the typical vertically integrated, fully regulated utility, owning generating assets, gas fields, and both transmission and distribution lines and facilities. It served most of the state's residential, commercial, and industrial customers, and had been in operation for more than 90 years.

Unlike many other states that enacted deregulation laws, Montana's law did not require MPC to divest itself of its generation assets, but it did allow such a move. The law also allowed for retail access for industrial customers beginning in July 1998, and for the remaining residential and small business customers beginning in July 2002. Rural electric cooperatives were given the option to determine whether their customers would be able to select an alternative retail provider.

The law also included a cap on prices for all customers for two years, beginning July 1, 1998. At the end of the two-year transition period, customers who still did not have access to retail choice would have their prices capped for an additional two years.

The first 18 months after passage of the EUIRCA were relatively uneventful, as some of MPC's industrial customers began switching to other providers in order to realize cost savings.<sup>2</sup>

However, beginning in 1999 several events sparked years of controversy and conflict around Montana's deregulation law. In December 1999, MPC sold all of its generation assets—including 11 hydroelectric facilities and two coal-fired power plants—to Pennsylvania Power and Light (PPL). The company also sold its electric transmission and distribution infrastructure to NorthWestern Energy, headquartered in South Dakota. As the "utility" now actually delivering electricity to consumers, NorthWestern had to buy power on the open market, including from the hydroelectric and coal plants previously owned by MPC, but now owned by PPL. PPL organized a subsidiary to operate the Montana generating assets it had purchased from the old MPC.

MPC used the proceeds of its sale to reorganize as Touch America, a telecommunications company attempting to enter the fiber optics business. The energy crisis surrounding California's deregulation process began driving up wholesale prices in 2000, and these prices affected many states in the West, including Montana.<sup>3</sup> Significant cost increases came for large customers that had taken advantage of the deregulation law and signed long-term contracts with independent power producers, including PPL. These firms were forced to scale back operations or cease them entirely. Some early advocates of deregulation, including Greg Stricker, president of Montana Resources, Inc., began calling for a return to a fully regulated system:

*The harsh reality of deregulation is that it relinquishes control of assets that are essential to the health and welfare of Montanans. Those assets were paid for by Montanans; those assets are now being used to reap huge profits at the expense of Montanans ... an immediate return to the full regulation of Montana's electricity market is the only way to ensure that all Montanans receive reasonably priced electricity now and in the future.<sup>4</sup>*

In 2001, several pieces of legislation were enacted in a bid to address the mounting problems associated with deregulation and rising prices. Implementation of retail access for residential and small business customers, originally scheduled to begin in 2002, was delayed for five years, until 2007. A "default supplier" was designated to provide electricity to customers who did not wish to choose alternative suppliers. Financial incentives were created to stimulate additional generation in the state. In addition, an authority was created—the Montana Power Authority—with powers to issue \$500 million in revenue bonds to purchase or build new generating capacity.<sup>5</sup>

This legislation, however, raised new concerns. Many observers claimed the bill's attempt to ensure all power supply costs incurred by the utility—now primarily NorthWestern Energy buying power from PPL—could be recovered shifted all of the cost burden for acquiring electricity to customers, and essentially shielded the utilities from any financial risk. They pointed to the fact that the bill was doing this in what was supposed to be a competitive market structure.<sup>6</sup>

What had been a legislative debate quickly became a public one when two separate initiatives were placed on the November 2002 ballot. The Montana Electrical Deregulation Changes Referendum (IR-117) was a veto referendum on HB 474, the legislation adopted in 2001 that contained the controversial power supply cost recovery provisions. The voters repealed HB 474, with 60% voting for its removal.<sup>7</sup>

Voters also tackled Initiative 145 on the same ballot. Initiative 145 was essentially an attempt to “buy back” the 11 hydroelectric facilities that MPC had sold to PPL in 1999. The proposal would have created a Montana Public Power Commission (repealing HB474’s provisions for a Power Authority) that would be run by a five-member, elected commission with authority to buy the hydroelectric facilities. The bonds would be paid off by power sales and the commission would have been given the state power of eminent domain if PPL did not voluntarily sell the dams. The backers of Initiative 145 expressed concerns about power prices, water rights, and out-of-state ownership of the generation assets located in Montana. Initiative 145, however, was roundly defeated, 68–32.

By 2007, market volatility, the lack of retail competition for small customers, and the political and legislative turmoil combined to prompt the Montana Legislature to pass the Electric Utility Industry Generation Reintegration Act of 2007, which effectively put an end to full customer retail access and allowed Montana’s NorthWestern Energy to build or purchase its own generation facilities.<sup>8</sup>

In recent years, Montana has seen a fairly rapid expansion of generation capacity ,

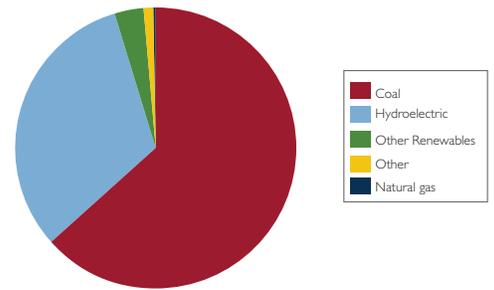
*Montana has suffered from the effects of electricity deregulation in the past decade. If that market can't be policed adequately and provide affordable energy for Montanans, we will consider creative ways to re-integrate Montana's electrical energy generation, transmission and distribution and the possible re-regulating of prices. We need to seek ways to ensure that adequate amounts of the electric energy produced at the lowest cost in this state are reserved for Montana's businesses, industries and families.*<sup>9</sup>

—Montana Governor Brian Schweitzer

largely due to increased renewable energy (wind) generation, as well as additional thermal and natural gas sources. More than 600 megawatts (MW) of installed wind capacity alone was added between 2006 and 2012. Much of this generation was developed to provide renewable energy credits for California and other western states.<sup>10</sup>

- ◆ Deregulated in 1997
- ◆ 1,890,000 MWhs of electricity generated in Montana
- ◆ Retail electricity sales (MWhs): \$13,423,138 (#41 in nation)
- ◆ Average electricity price (cents/kWh in 2011): 8.23 (#36 in nation)
- ◆ Exports about half of the electricity generated in the state to other states

Generation by source (MWh)



SOURCE: Public Sector Consultants, based on data from the U.S. Energy Information Administration, Form EIA-923, “Power Plant Operations Report” and predecessor forms.

## TIMELINE

**April 1997**—Montana Governor Marc Racicot signs Electric Utility Industry Restructuring and Customer Choice Act, which allows industrial customers retail access beginning July 1998, and all others (residential and small business) retail access beginning July 2002

**July 1998**—Industrial customers begin retail access

**December 1999**—Montana Power sells 100 percent of its generating assets to Pennsylvania Power and Light Corp. (PPL)

**1998 to 2002**—Montana Power Company divests itself from the electric utility business to pursue fiber optics business (reorganizing as Touch America); sells 11 hydroelectric dams and two coal-fired power plants to PPL for \$836 million in 1999<sup>11</sup>, and electric transmission facilities to NorthWestern Energy for \$612 million in 2002<sup>12</sup>

**2001**—Montana Legislature passes a bill to delay full electric retail access for all customers until July 2007 because retail access had not developed for small residential and customers

**July 2002**—Rate caps under EUIRCCA expire and electricity rates begin to rise

**November 2002**—Voter Initiative 145 fails at ballot, but a voter referendum repeals a controversial electric rate measure (HB 474)

**June 2003**—Touch America (former Montana Power Company) files for bankruptcy

**2007**—Montana begins “re-regulation” when legislature passes Electric Utility Industry Generation Reintegration Act, which halts consumer electric access for users under five megawatts, and allows NorthWestern Energy to vertically integrate by building/owning its generating facilities

**September 2013**—NorthWestern Energy announces plans to spend \$900 million to purchase the hydroelectric dams that were sold to PPL as part of deregulation

September 2013 marked another important time in the Montana deregulation story, when NorthWestern Energy, which purchased the transmission and distribution assets of the old MPC, announced plans to spend \$900 million to buy the 11 hydroelectric dams that MPC originally sold to PPL in 1999. The purchase of these facilities—if approved by the Montana Public Service Commission—represents an attempt to re-create a traditional utility that owns the generation, transmission, and distribution assets, and whose operations and rates are regulated by state government. If the plan is executed, Montana will have come full circle on electric degeneration.

## Issues

### *Bankruptcy of the State's Utilities*

One of the negative economic effects of Montana's experiment with deregulation was the rapid and unexpected bankruptcy of MPC. MPC, the state's largest power provider and only Fortune 500 company, was an early proponent of Montana's deregulation law. Shortly after deregulation went into effect, MPC sold all of its energy generation assets, and along with them the valuable senior water rights on the rivers with hydroelectric facilities, to an out-of-state independent power provider—PPL. It also divested itself of its transmission and distribution assets, selling them to NorthWestern Energy.

MPC invested the \$2.7 billion from the energy facility sales in an extensive fiber optic cable network, and reorganized under one of its subsidiaries, Touch America, a telecommunications company. This investment in telecommunications came just as the high-tech stock market bubble was about to burst. MPC had been a long-term, steady employer and investment for many Montanans. At the time it began divesting from the energy business, the company employed more than 3,000 people and had a stock value of \$64 per share. By 2003, the stock price of Touch America had dropped to 33 cents per share. The company ultimately filed for bankruptcy protection, wiping out \$2.7 billion in value for investors and employee pensions.<sup>13</sup> Many shareholders were unaware that their investment in the 80-year-old company was substantially changing until they had lost much or all of their investment.

In addition to MPC's bankruptcy, the years following deregulation of Montana's electric utility industry brought financial troubles for NorthWestern Energy, owner of the majority of Montana's electric transmission and distribution system. The company mostly financed the \$1.1 billion purchase of MPC's transmission and distribution infrastructure through debt. This move, combined with the company's aggressive expansion outside the utility industry in the prior four years, eventually drove the company into bankruptcy. Just nine months after the purchase of MPC's assets, NorthWestern Energy filed for Chapter 11 bankruptcy protection in September 2003. Unlike MPC, however, NorthWestern survived. By late 2004, the company was able to emerge from bankruptcy protection. With its plan, announced in September 2013, to purchase the hydroelectric

facilities originally sold by MPC to PPL in 1999, NorthWestern will become a vertically integrated, fully regulated utility, owning generation, transmission, and distribution assets.

### *Majority of Montana's Generating Assets Owned by an 'Out-of-state' Company*

With MPC's sales of its electric generating assets to PPL, the vast majority of the state's generating assets were now held by an out-of-state company. When electricity prices rose rapidly throughout the West in 2000–01, significant controversy and anger arose over the fact that an out-of-state firm was benefiting financially by selling Montana customers high-priced power generated by Montana-based facilities managed by people in Montana. At the same time, the remnants of Montana's historic electric utility—which had previously owned those same generating facilities—was going through bankruptcy.

*“By getting out of utilities and into telecommunications, Montana Power/Touch America had bought into the biggest stock market bubble in American history. Just before it burst.”*

—CBS' 60 Minutes, "Who Killed Montana Power"

Compounding the issue, PPL gained the senior water rights on several rivers in the state, including the Flathead River, Clark Fork River, Missouri River, Madison River, and West Rosebud Creek. Montana is a prior appropriation water law state, which means water rights are granted on the “first in time, first in right” method. As senior water rights holder, PPL had the right to make a call for its full share of water in these basins to meet the hydroelectric needs at those dams. As a result, more junior rights holders, particularly farmers needing irrigation and other industrial and municipal users, might not be able to use water in these rivers during parts of the year, or not at all in some drought years. Since the early 1990s, water in the Clark Fork and Missouri Rivers, for example, has been unavailable for use by junior rights holders, except during periods of high spring runoff (two to three months a year).<sup>14 15</sup> In the arid West, this level of control over scarce water resources by an out-of-state company only added to the controversy and dissatisfaction with PPL's ownership of the hydroelectric facilities.

### *Affordability—Prices in Wholesale Market*

Montana's appetite for deregulation essentially disappeared when prices in the wholesale market fluctuated wildly in 2000–01. Historically, Montana always had some of the lowest electricity prices in the country, with prices comparable to other states in the Mountain West. In the year preceding the passage of the Electric Utility Industry Restructuring and Customer Choice Act, electricity prices in Montana were just under \$0.05/kWh, compared to the U.S. average of almost \$0.07/kWh.<sup>16</sup> The proposed legislation was brought forward by the Montana

Power Company and a number of Montana's large industrial customers, on the premise that more competition would be good for Montana's customers and provide lower prices over the long term.

Immediately after deregulation, some of MPC's industrial customers began switching to other providers in order to realize cost savings. However, as the energy crisis surrounding California's deregulation process was driving up wholesale prices, large customers whose contracts expired in the early 2000s scaled back or ceased operations in the face of enormous electricity cost increases. As noted earlier in this report, these price increases prompted one of the early advocates of deregulation, Greg Stricker, president of Montana Resources Inc., to call for a return to full regulation.

Residential and small commercial customers were sheltered from the 2001 wholesale electricity price spike, but when the price caps were lifted in 2002, wholesale prices were climbing, and all customers saw significant cost increases for their electricity.<sup>17</sup> Prior to deregulation, Montana's electricity prices were competitive from a regional perspective—not the lowest, but also not the highest. During its decade of deregulation, however, Montana has had the highest prices in the region.

### *Paying Twice for the Same Assets?*

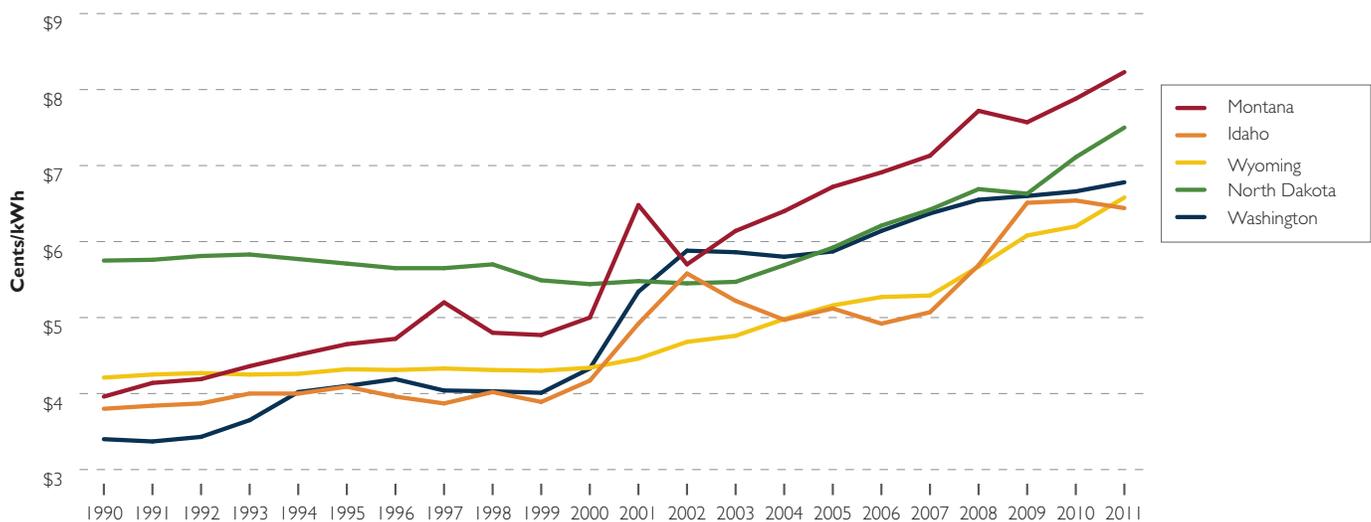
The state's efforts to abandon deregulation and NorthWestern Energy's pursuit of generation facilities to once again have vertical integration of electricity supply and delivery systems have created the outstanding question of whether Montana ratepayers have paid twice for the same generating assets.

The issue has been raised because the hydroelectric facilities NorthWestern Energy is purchasing from PPL were originally constructed by MPC and paid for by ratepayers. In other words, the capital costs were built into the customers' rates to pay off the debt over time. When MPC sold those electricity generation assets to PPL in 1999, the profits were largely sunk into Touch America's fiber optic network infrastructure system, although customers no longer had those generation assets in their rate base and were provided a modest 4 percent rate reduction in energy costs through the remainder of the transition period (which ended June 30, 2002).

Under the state's Electric Utility Industry Generation Reintegration Act, NorthWestern Energy will be able to build those purchase costs into its customers' rate base, and NorthWestern's application with the Montana Public Service Commission in December 2013 to do so indicates this will cost the average residential ratepayer about \$3.53 per month—an increase of 4.22 percent.<sup>18</sup>

It is not clear, however, that simply allowing NorthWestern to recoup its "repurchase" of these generating assets from the ratepayers over time means that ratepayers will have paid twice for the same assets. The rate reduction at the time of the original sale in 1999 and removing these assets from the rate base may have been enough to compensate ratepayers—and NorthWestern states this in its December 2013 application with the Montana Public Service Commission.<sup>19</sup> The complexities of rate-making and the financial relationship between ratepayers and shareholders, and the simple fact that the values of electric generation assets change over time with market conditions, mean this question may never be answered to everyone's satisfaction.

Historic Electricity Prices in Montana and Surrounding States



SOURCE: EIA State Profiles and Energy Estimates Database

## Conclusion

Montana has experienced utility bankruptcies, wholesale price increases in 2000–01, debates about the impact of out-of-state ownership of Montana-based generating facilities, as well as considerable political and legislative turmoil surrounding the issue of electricity deregulation. The state's experiment with deregulation did not deliver lower prices over the long term, and it resulted in several unintended economic consequences for the state, including the need to repurchase previously owned electric generating assets.

When the EUIRCA was passed in 1997, Montana, like much of the West, enjoyed some of the lowest electricity prices in the country. While large industrial customers benefitted from lower electricity prices initially, volatile and climbing wholesale electricity prices after

the transition period price caps were lifted left many of Montana's largest industrial customers vulnerable to substantial increases in energy costs—causing many to scale back their business or cease operations entirely. Electric choice providers for smaller residential and commercial customers never fully materialized, and the state twice delayed implementation of electric retail access for these customers.

In 2007, the state finally put an end to deregulation efforts with the passage of the Electric Utility Industry Generation Reintegration Act. The act allowed Montana's NorthWestern Energy to build or purchase its own generation facilities. In September 2013, the firm announced it would do just that, saying it would purchase hydro-electric facilities that were sold by MPC in 1999

*The legacy of deregulation in Montana includes the disintegration of a Fortune 500 company, the loss to Montana of one of the nation's least expensive and most stable sources of electric supply, explosive rate increases that shocked residents, businesses, and the state economy during the years that deregulation took full effect, the near-instantaneous meltdown of the Montana Power Company's corporate telecom progeny (Touch America), the vaporization of savings and retirement accounts that had been built around stock holdings in a century-old company, and a cost of electricity to Montanans that will be forever higher than what it would be had deregulation not occurred.*

—Bob Decker, The Policy Institute

## Endnotes

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## Conclusions

Electric deregulation surged onto the policy scene in the mid-1990s as some states began restructuring their electric utility markets. Since then, debate has waxed and waned about the effects—good and bad—of greater retail access. After the price spikes, rolling blackouts, and utility bankruptcies that accompanied California's energy crisis in 2000–2001, and as and as other states experienced similar challenges, some began to pull back from their deregulation efforts. Sixteen states and the District of Columbia now have active electricity restructuring laws, while seven states have suspended their deregulation efforts.

PSC's look at the experiences of four states is intended to provide a brief picture of the issues that have accompanied those states' restructuring work. Retail costs were the driving factor for most states in pursuing deregulation, yet, for the four states PSC evaluated, promised price drops never materialized for all customers. Electricity rates for industrial customers in one of the states declined in the early years of deregulation, but climbed again after initial power delivery contracts expired and wholesale prices increased.

While all four reviewed states struggled with price trends, two also had issues with capacity and/or reliability of their electric markets after the implementation of retail choice. And all four states have wrestled with other unintended consequences. New Jersey, for example, has found itself in a struggle with its regional transmission organization and the federal government over its efforts to retain state control of its energy policy. Montana experienced the bankruptcy (and associated economic ripples) of its largest utilities and out-of-state ownership of the bulk of its generation assets. Illinois felt compelled to create a new state agency to oversee planning and procurement of electricity and generation capacity. And Texas, although cited by some industry observers as a leader on deregulation, still faces significant capacity shortages and is considering additional government interventions to ensure adequate power supplies.

The experiences of these four states, although covering only a portion of the deregulation landscape, offer lessons that could be applicable to Michigan as it considers its “no regrets” energy policy options. It is important for Michigan policymakers and residents to understand how deregulation not only affects customer prices, but also overall system reliability, the state's role in planning for and protecting affordable and reliable electricity supplies, and broader economic development and stability.

Prepared by

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PUBLIC SECTOR  
CONSULTANTS

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