RETAIL COMPETITION IN ELECTRICITY

WHAT HAVE WE LEARNED IN 20 YEARS?

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Glossary

Franchise Agreements – Agreements with the local communities the IOUs serves. In general, these agreements provide the IOU with the exclusive right, and obligation, to serve the community's customers as well as access to rights of way.

Investor Owned Utility ("IOU") – A privately owned entity that serves as a public utility, provides utility service to customers, and is typically regulated by a government entity such as a state public utility commission.

Independent System Operator ("ISO") or Regional Transmission Organization ("RTO") – ISOs and RTOs are not-for-profit entities that are formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs.

Locational-Marginal Pricing – The value of electricity at hundreds and sometimes thousands of different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system.

Microgrid – When a large customer or group of customers (e.g., hospitals or municipalities) deploy distributed resources to attain a higher degree of resiliency. This may also include the ability to "island" – whereby power remains on in the microgrid when there is no power to the larger grid.

Phelps-Dodge Decision – Arizona Court of Appeals Decision 1 CA-CV 01-0068, which ruled that certain ACC rules regarding competitive markets and market rates were unconstitutional.

Price to Beat – In Texas, a price that was designed as a price floor to prevent the incumbent providers from offering artificially low rates to stifle competition and undercut new market players.

Provider of Last Resort ("POLR") – A company who is required to provide service to customers who for some reason (e.g., their chosen supplier goes out of business) do not have a competitive service provider.

Retail Energy Supplier, Retail Electric Provider, Retail Marketer, Competitive Supplier, or Energy Service Company ("ESCO") – A company that serves as a middleman or an intermediary between the electricity buyer (residential, commercial and industrial customers) and the wholesale electric market. Retail marketers purchase electricity through wholesale electricity markets and resell it to consumers.

Slamming – Unauthorized switching of customers to a competitive supplier without proper authorization from customers.

Stranded Costs – Costs that are created when the market value of utility assets in a restructured market is less than the net book value on the utilities' books.

Vertically-Integrated Utilities – Utilities that own all levels of the supply chain (generation, transmission, and distribution).

List of Abbreviations

ACC	Arizona Corporation Commission
AG	Attorney General
APS	Arizona Public Service Company
Az ISA	Arizona Independent Scheduling Administration Association
CCA	Community Choice Aggregation
CAISO	California ISO
CPP	Critical Peak Pricing
CTA	Competitive Transition Assessment
CTC	Competitive Transition Charge
DOE	Department of Energy
EDR	The Office of Economic and Demographic Research
EIA	Energy Information Administration
EIM	Energy Imbalance Market
ERCOT	Electric Reliability Council of Texas
ESCO	Energy Service Company
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIEC	Financial Impact Estimating Conference
HOA	Homeowner's Association
IOU	Investor Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	ISO New England
LMP	Locational-Marginal Price
LNG	Liquefied Natural Gas
MISO	Midwest ISO

NERC	National Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York ISO
NY PSC	New York Public Service Commission
PJM	Pennsylvania-New Jersey-Maryland Interconnection
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PUCN	Public Utilities Commission of Nevada
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
SB7	Texas Senate Bill 7
SPE	Special Purpose Entity
SPP	Southwest Power Pool
ROE	Return on Equity
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
RTP	Real-Time Pricing
SRP	The Salt River Project
T&D	Transmission and Distribution Systems
TCAP	Texas Coalition for Affordable Power
TCE	Texas Commercial Energy
TOU	Time of Use
TEP	Tucson Electric Power
ZEC	Zero Emission Credit

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I. Executive Summary

This report, commissioned by the Arizona Energy Policy Group ("AEPG"), provides a fact and research-based review of electric restructuring actions, initiatives, successes and failures over the past twenty years.[1] Highlights of this report follow.

A. Regulation and Restructuring

In a traditionally regulated market, like Arizona, vertically integrated regulated utilities own and/or contract for generation, and own and operate transmission and distribution systems and provide electricity to their retail customers within specific service territories at regulated rates established by state regulators.[2] In many traditionally regulated states, state commissions review integrated resource plans ("IRPs") prepared by investor owned utilities ("IOUs") evaluating the energy needs of their customers and how best to meet those needs. State regulatory commissions also implement public policy through their regulation of electric utilities. For example, many states have implemented renewable portfolio standards requiring IOUs to include a certain amount of renewable generation in their supply portfolios.

In a fully restructured system, IOUs are either not permitted or must compete with others to provide generation service and instead provide transmission and distribution service only. IOUs typically are required to "divest," or sometimes spinoff their generating assets, historically creating substantial stranded costs that are recovered from electricity customers. Independent Power Producers ("IPPs") own and operate generation resources. An Independent System Operator ("ISO") or a Regional Transmission Organization ("RTO") manages power system planning, provides administration for the wholesale power market, operates the bulk electric power system and is tasked with ensuring power reliability. An Independent Market Monitor provides oversight to ensure fair trade practices but not rate regulation. Retail marketers, retail energy suppliers, competitive suppliers, or energy service companies ("ESCOs") act as intermediaries between retail customers and the wholesale power market. In most restructured states when a customer does not select a retail marketer or when there is a retail marketer failure (e.g., default), customers are put on Standard Offer or Provider of Last Resort ("POLR") service which acts as a backstop to ensure customers will continue to receive electricity. Municipal ("Munis") and Cooperative ("Coops") utilities are typically exempted from retail restructuring.

The role of state regulators in a restructured energy market is primarily focused on delivery service. State regulators no longer oversee the resource plans or establish rates for generation service. State regulators' (and policy makers') influence over the generation segment of the market is reduced and relies largely on their participation in proceedings at the Federal Energy Regulatory Commission ("FERC").

B. Survey of U.S. States

Twenty-five states have actively considered electric restructuring. Fourteen states have implemented full retail competition for all customers of IOUs. Seven states have implemented partial retail competition, in some cases starting with full retail competition and ultimately re-regulating

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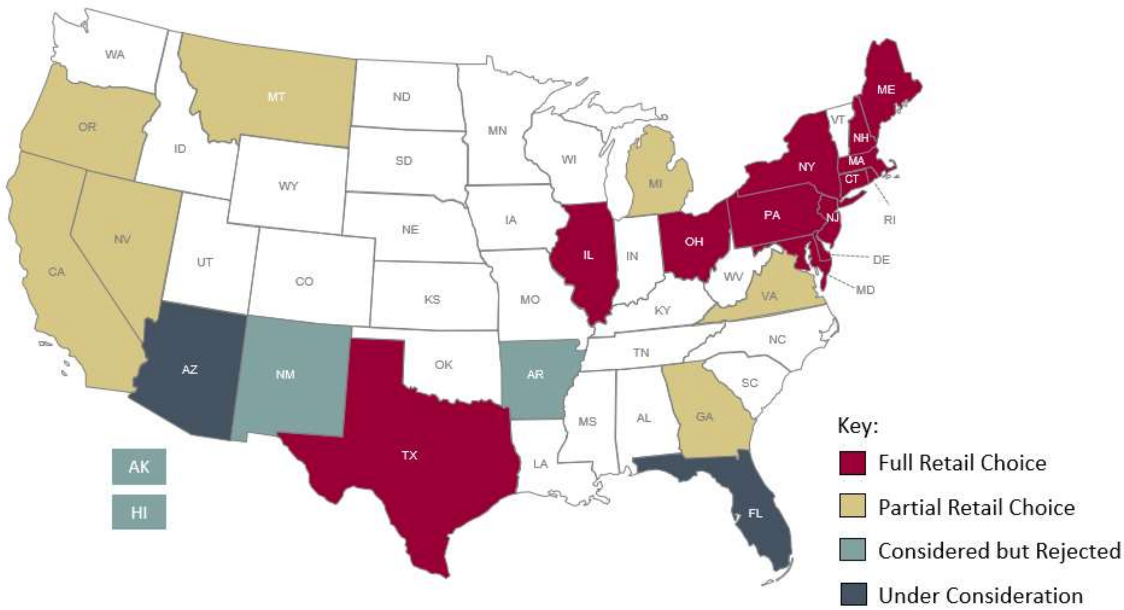
1 Throughout the report, terms such as "retail choice", "restructuring" and "retail competition" are generally used interchangeably.

2 In some areas electric service is provided by Munis or Coops.

portions of the state's electricity markets. Other states have actively considered retail competition but ultimately chose not to restructure their electricity markets.

Figure ES-1: Electric Restructuring State Map



In Nevada, a statewide ballot initiative to provide retail competition for all customers went before voters in both the November 2016 and 2018 general elections. After significant time and expense, the voters of Nevada decided not to move forward with restructuring.

In Florida, Citizens for Energy Choice, a group led by Infinite Energy, a wholesale and retail energy marketer, is seeking to include on Florida's 2020 ballot a measure to create a constitutional right to retail competition, among other things. The state's Financial Impact Estimating Conference ("FIEC") concluded that the proposed amendment would result in "significant costs to state and local government," and that, "significant legal and litigation expenses are probable" among other factors.[3] The ballot measure is now at the Florida Supreme Court and a decision about whether the measure may be placed on the ballot if it receives the required number of signatures in support is expected in the fall.

Arizona has considered retail restructuring on and off for decades.[4] Over the past year, the Arizona Corporation Commission ("ACC") opened Docket No. RU-00000A-18-0284 to explore a wide range of energy rules primarily focused on renewables but also listing "Retail Electric Competition" as a potential item for discussion. On May 3, 2019, ACC Chairman Burns announced that the commission would be holding workshops on retail electric competition (Docket No. RE-00000A-18-0405).[5] Chairman Burns stated that he would like the following topics at a minimum to be addressed: Community Choice Aggregation ("CCA") for groups such as Homeowners Associations ("HOA"), developments without HOAs, neighborhood community groups, special districts, etc.; and microgrids

3 Florida Financial Impact Estimating Conference, Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice, Serial Number 18-10, March 15, 2019, page 1.

4 S&P Global.

5 https://docket.images.azcc.gov/E000000700.pdf

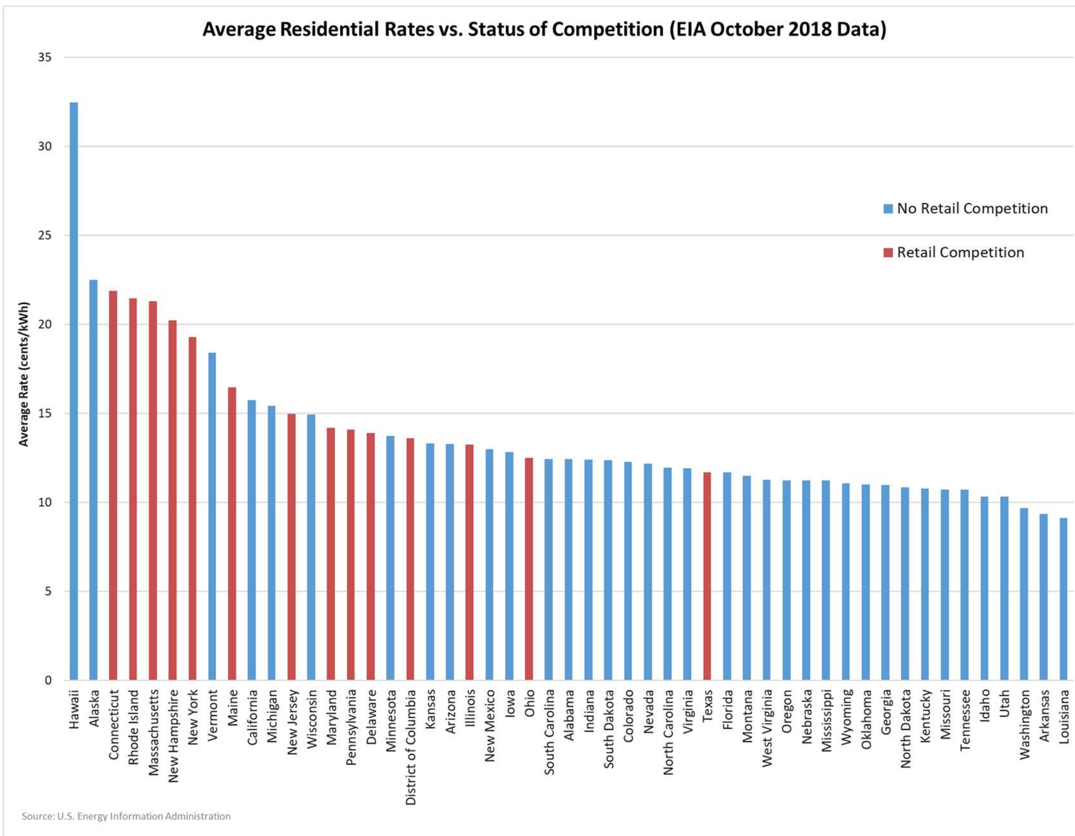
being able to operate independently of the interconnected grid in the event of an outage (accidental, planned, or natural disaster) on the interconnected grid.

C. Retail Rates for Residential Customers

In general, available evidence does not support the assertion that retail competition will necessarily lower rates for residential customers. While some studies conclude positive or negative price impacts, other academic and industry research finds that there is no conclusive link between pricing advantages for retail customers and electric industry restructuring.

While numerous factors impact electric prices, the following chart illustrates that many states with higher residential rates have full retail competition:

Figure ES-2: Average Residential Rates by State



Source: EIA, Electric Power Monthly, October 2018

Many states have recently completed evaluations of whether residential and small commercial customers are better or worse off by switching to retail providers. For example, parties in the following restructured states have concluded that consumers who took service from competitive suppliers paid more than they would have paid the default supplier:

Table ES-1: Cost Differences between Competitive Suppliers and Default Service

State	Party	Approximate Timeframe	Approximate Cost to Consumers
Connecticut	Office of Consumer Counsel	2015	$58 million
Illinois	Attorney General	2014-2018	$600 million
Massachusetts	Attorney General	2015-2018	$253 million
New York	Public Service Commission	2014-2017	$820 million

In addition, a Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million more than the default service costs.[6] The Texas Coalition for Affordable Power found that restructuring had cost Texas customers $22 billion from 2002 – 2012.[7]

D. The Need for a Fully Functioning Wholesale Market

All states that have restructured their electricity markets to provide full retail competition (commercial, industrial and residential) are part of either an ISO or RTO. ISOs/RTOs are not-for-profit entities that were formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs. The initial formation of an ISO/RTO and establishment of energy, ancillary and potentially capacity markets have taken several years and hundreds of millions of dollars. In addition to upfront implementation costs, there are substantial on-going annual costs to administer an ISO or RTO.

The organizations that Arizona IOUs can or do participate in today are not ISOs/RTOs. The Western Energy Imbalance Market ("EIM") operated by the California Independent System Operator ("CAISO"), whose participation includes Arizona Public Service Company ("APS") and is growing, is a real-time only energy market and does not offer all of the products, services, benefits, and efficiencies of a fully functioning wholesale market. When Arizona was originally contemplating full restructuring, the state established the Arizona Independent Scheduling Administrator Association ("Az ISA") in 1998 as a first step toward the more robust structures that would be necessary to oversee a competitive retail electric marketplace. The Az ISA still exists today but is essentially inactive.

E. Resource Planning and Reliability

In regulated markets, IOUs develop detailed plans to meet their customers' electricity needs over a multi-decade time horizon. This ensures that the IOUs have a diverse portfolio of resources, reflective of the state's energy policies, and sufficient to serve their customers. In a restructured market, the amount and type of new generation is primarily determined by market forces, and resource planning is largely removed from the jurisdiction of the public utility commission and the state in general.

Restructured markets have been challenged in their ability to provide the compensation needed by critical resources to meet system reliability needs. Texas provides a recent example of insufficient generation coming into the market. Reserve margins in Texas have decreased since the introduction

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6 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, page 9.

7 TCAP 2014 Electric Restructuring Report.

of restructuring in the state. Reserve margins serve as a measure of the generating capacity that is available to meet customer demand. The Electric Reliability Council of Texas ("ERCOT") projects reserve margins in the summer of 2019 of 7.4% as compared to ERCOT's target reserve margin of 13.75%.[8] Chairman of the Public Utilities Commission of Texas ("PUCT") DeAnn T. Walker called the 7.4% projection "very scary."[9] In its Seasonal Assessment of Resource Adequacy for summer 2019, the commission reported: "In all of the scenarios studied … ERCOT identified a potential need to enter Energy Emergency Alert ("EEA") status in order to maintain system reliability."[10]

Some states have implemented special programs to keep generating plants operating. New York[11] and Illinois[12] have Zero Emission Credit ("ZECs") programs, which provide subsidies for nuclear generation, as part of the NY Clean Energy Standard (finalized by the New York Public Service Commission ("NY PSC") in August 2016) and Illinois statute (passed in December 2016). These programs have been challenged in state and federal courts by competitive market proponents.[13]

F. Generation Divestiture and Stranded Costs

In many restructured states, IOUs were prohibited from owning generation, and were required to divest of their existing generation assets, resulting in "stranded costs." Stranded costs are created when the market value of utility assets in a restructured market is less than the value on the utilities' books. Stranded costs are then recovered from customers through their bills. In states that have restructured, including California, Connecticut, Illinois, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, Pennsylvania and Texas, utilities have been authorized to recover over $36 billion in stranded costs.[14] Stranded costs were also considered in Nevada in the context of the recent ballot initiative to restructure that state's electric market.[15] During the Public Utility Commission of Nevada's ("PUCN") investigation of the proposal, NV Energy submitted several reports and comments that outlined the risks involved with restructuring, including stranded costs. J.P. Morgan and ICF International estimated that stranded costs would range from $5.18 billion to $6.13 billion, the majority of which related to retiring baseload generation.[16]

G. Transition in Generation Fleet

Recent decades have seen a dramatic shift in the U.S. generation fleet in both restructured and non-restructured states.

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8 ERCOT, "High demand and tight reserves may result in energy alerts this summer," March 5, 2019, http://www.ercot.com/news/releases/show/176704. (Note: as of December 2018, ERCOT had forecasted a reserve margin of 8.1% but this fell after the loss of Gibbons Creek. See: ERCOT Capacity, Demand and Reserves Report, December 2018.)

9 Bade, G., "Texas regulators direct higher plant payments amid capacity crunch concerns," Jan. 22, 2019. (https://www.utilitydive.com/news/texas-regulators-direct-higher-plant-payments-amid-capacity-crunch-concerns-1/546540/)

10 ERCOT Seasonal Assessment of Resource Adequacy – Summer 2019 Final Seasonal Assessment. Available: http://www.ercot.com/gridinfo/resource.

11 "Why Court Victories for New York, Illinois Nuclear Subsidies are a Big Win for Renewables." Julia Pyper, Greentech Media. July 31, 2017.

12 State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois"

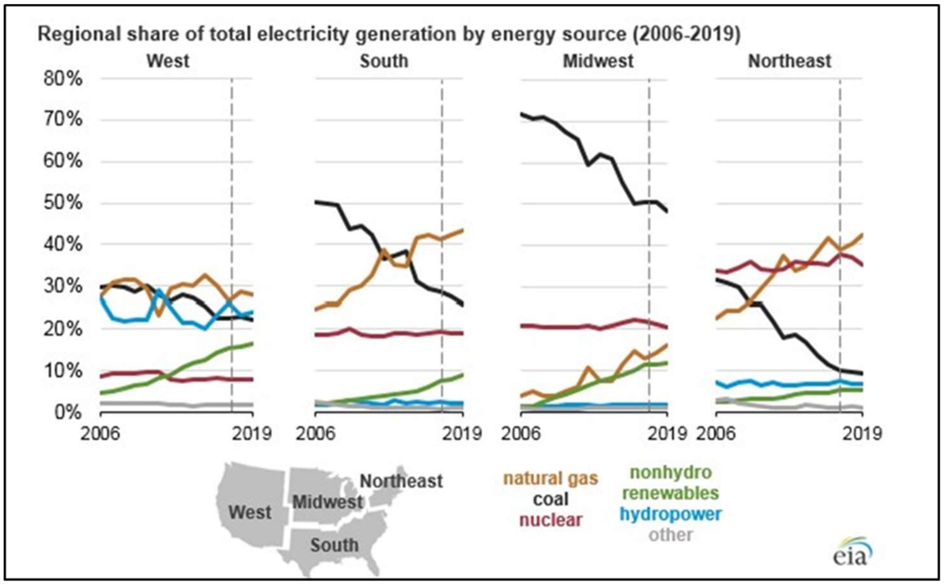
13 State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois."

14 Source: Regulatory Research Associates, "Utility Asset Securitization in the U.S.," March 4, 2013. Supplemented by Concentric research.

15 Energy Choice Initiative Final Report, Investigatory Docket No.17-10001, PUC of Nevada.

16 Final Comments, Nevada Power Company NV Energy and Sierra Pacific Power Company, Docket No.17-10001, page 1.

Figure ES-3: Trends in Electric Generation by Energy Source by Region



A recent analysis of generation related trends in restructured versus non-restructured states concluded that "In both the [states without retail competition] and [states with full retail competition] groups, there has been a substantial shift in electricity production fuel mix from coal toward natural gas. In this respect, the trends in both groups have been similar;" this analysis made similar conclusions regarding comparable wind and solar generation trends in both groups.[17] Energy policies (other than restructuring policy) at numerous levels have supported the transition of the electric generation fleet. Federal tax credit policies have helped to drive large scale wind and solar deployment in particular (the production tax credit for wind and the investment tax credit for solar). Perhaps the most significant driver in transition of the electric generation fleet has been cost declines in generating resources. Similar to the impact of shale gas on the growth of natural gas generation, cost declines in wind and solar PV have supported their broad scale deployment. It is important to note cost dynamics apply and are addressed in traditionally regulated states as well as in restructured states.

H. Innovation in the Electric Industry

There have been a number of key innovations in the electric sector over the past 20 years including: (1) innovative pricing products; (2) advanced metering infrastructure; (3) green energy products; (4) energy storage; (5) electric vehicles; and (6) microgrids.[18] While industry structure may play a role, there are numerous factors that support electric sector innovation, including broader state policy. Further, while there may be some degree of variance depending on the specific innovation, overall there is meaningful adoption of all these innovations both in restructured and non-restructured environments.

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17 O'Connor, Phillip R., Ph.D. and Khan, Muhammad Asad, "The Great Divergence in Competitive and Monopoly Electricity Price Trends," Retail Energy Supply Association, September 2018, pages 7-8.

18 While not used as an authoritative source for this selection of key innovations, this list bears significant alignment with two recent industry listings regarding innovative electric sector activity: Bede, Gavin, Utility Dive, "The top 10 trends transforming the electric power sector" (Sep. 17, 2015); Girouard, Coley, Advanced Energy Economy, "Top 10 Regulation Trends of 2018 – So Far" (July 18, 2018).

II. Introduction

A. Background and Purpose of Report

Concentric Energy Advisors, Inc. ("Concentric") was retained by the AEPG to prepare a report reviewing the current state of retail competition in the electric industry. The report provides a fact and research-based review of electric restructuring actions, initiatives, successes and failures over the past twenty years. The intended use of the report by AEPG is to inform policy makers in states considering retail competition.

B. Arizona Energy Policy Group

AEPG is a pending 501(c)(6) non-profit organization founded to provide perspective to state and national regulators regarding Arizona's energy challenges and opportunities while learning from other states about successful energy policies to pursue and harmful polices to avoid. AEPG's members include investor-owned and public power utilities in Arizona that serve millions of state residents.

C. Concentric Energy Advisors, Inc.

Concentric is an economic advisory and management consulting firm, headquartered in Marlborough, Massachusetts, which provides consulting services related to energy industry transactions, energy market analysis, litigation, and regulatory support. Our regulatory economic and market analysis services include utility ratemaking and regulatory advisory services, energy market assessments, market entry and exit analysis, corporate and business unit strategy development, demand forecasting, resource planning, and energy contract negotiations. Our financial advisory activities include both buy and sell side merger, acquisition and divestiture assignments, due diligence and valuation assignments, project and corporate finance services, and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

D. Report Methodology

The report relies upon Concentric's research using publicly available sources of information. This includes company, state regulatory commission and ISO/RTO websites, public state regulatory and Securities and Exchange Commission ("SEC") filings, academic research, and other publicly available information on the subject of electric industry restructuring. Concentric also utilized its subscription services for data acquisition and analysis, as well as other content. This research and data were then assembled and reviewed by Concentric's team of professionals.

E. Report Organization

The report is organized into the following chapters:

I. Executive Summary

II. Introduction

III. Arizona's Electric Market

IV. Regulation and Restructuring

V. Survey of U.S. States

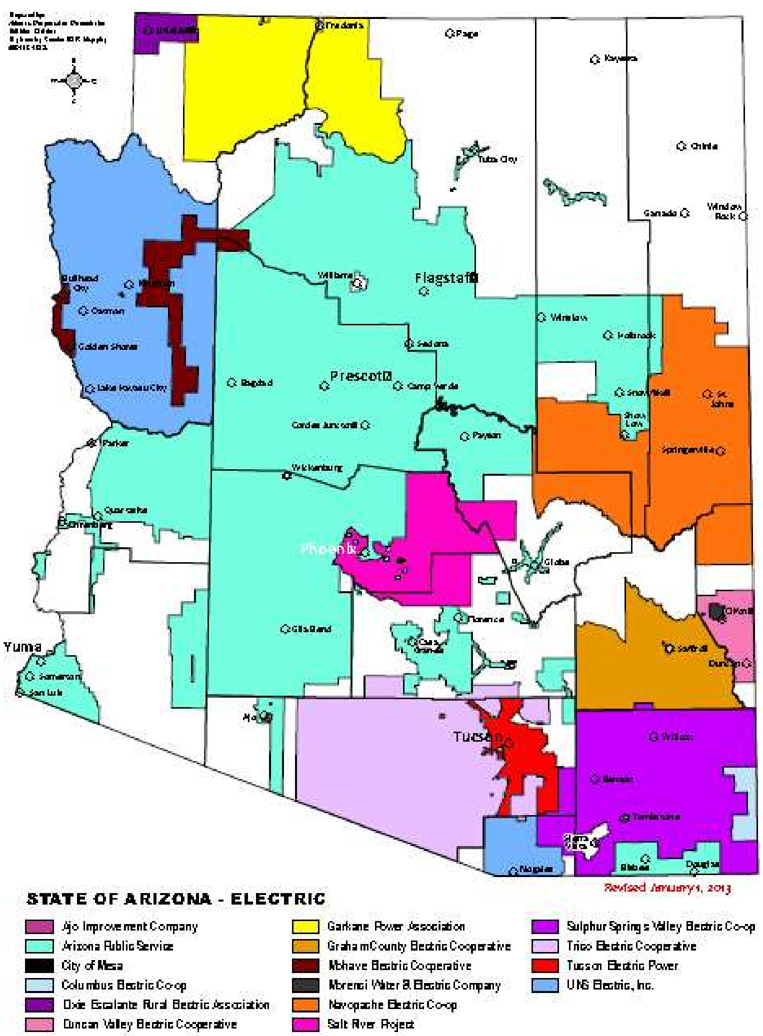
VI. Wholesale Market Considerations
VII. Retail Market Considerations
VIII. Generation Divestiture and Stranded Costs
IX. Transition in Generation Fleet
X. Restructuring and Innovation

III. Arizona’s Electric Market

A. Introduction

Arizona’s retail and wholesale electric markets are traditionally regulated. Arizona is served by a combination of IOUs, a political subdivision, municipally or cooperatively owned electric companies, and tribal authorities.

Figure 1: Arizona Electric Utility Service Territories[19]



Arizona’s three largest IOUs, APS, Tucson Electric Power (“TEP”), and UNS Electric, Inc. (“UNS”), serve approximately 56% of the state’s retail electric customers and are regulated by the ACC. The Salt River Project (“SRP”), a political subdivision of the state of Arizona, serves approximately 34% of the

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19 https://www.aps.com/en/communityandenvironment/economicdevelopment/Pages/service-territory-map.aspx.

state's retail electric customers. The remaining 10% of retail electric customers are served by Munis, Coops or tribal authorities.

Table 1: Arizona Utilities - Key Statistics[20]

Size Rank (Customers)	Company Name	Ownership Structure	Retail Electric Customers	Retail Electric Revenue ($000)	Retail Electric Volume (MWh)
1	Arizona Public Service Company	IOU	1,214,627	3,407,017	28,018,011
2	Salt River Project	Agricultural Improvement District	1,044,846	2,826,922	28,367,551
3	Tucson Electric Power Company	IOU	422,544	961,832	8,925,932
4	UNS Electric, Inc.	IOU	96,168	160,102	1,659,423
5	Sulphur Springs Valley E C Inc	Mutual/ Co-op	51,716	104,200	826,539
6	Trico Electric Cooperative Inc.	Mutual/ Co-op	45,895	94,245	696,117
7	Mohave Electric Cooperative, Inc.	Mutual/ Co-op	40,836	72,225	689,996
8	Navopache Electric Cooperative, Inc.	Mutual/ Co-op	39,307	47,075	378,669
9	Mesa City of	Government Agency	16,716	32,396	323,885
10	Graham County Electric Cooperative Inc.	Mutual/ Co-op	8,104	15,024	128,892
11	Morenci Water & Electric Company	Stock Corporation	2,696	108,257	2,675,904
12	Dixie Escalante R E A Inc	Mutual/ Co-op	2,378	2,493	32,134
13	Duncan Valley Electric Cooperative Inc.	Mutual/ Co-op	2,072	2,899	22,728
14	Garkane Energy Cooperative Inc.	Mutual/ Co-op	1,409	3,578	35,442
15	Ajo Improvement Company	Stock Corporation	980	826	7,596
16	Columbus Electric Cooperative Inc.	Mutual/ Co-op	490	890	6,171
	Other20F[21]	Other	97,909	304,024	3,742,166
		Total	3,088,693	8,144,005	76,537,156

20 SNL.

21 "Other" also includes several tribal systems such as Aha Macav Power Service, Ak-Chin Energy Services, and the Navajo Tribal Utility Authority Company, among others.

B. Generation

Arizona's state-wide generation fleet includes nuclear, natural gas, coal, solar, hydro, wind and biomass resources.

Figure 2: Generation Capacity by Type[22]

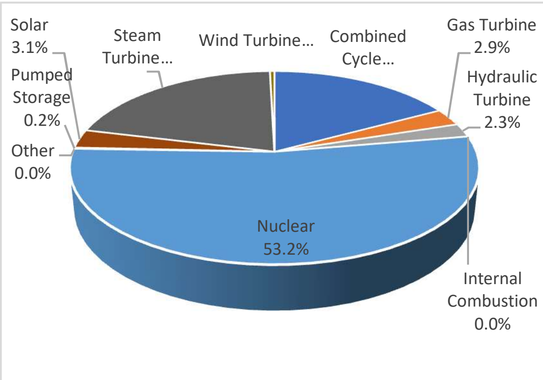
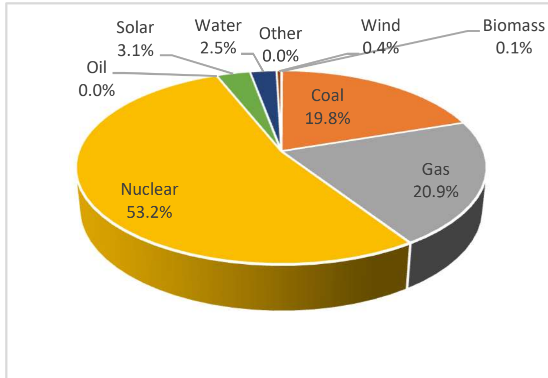


Figure 3: Generation Capacity by Fuel[23]



As shown above, nuclear is a significant part of Arizona's generation portfolio. Arizona is home to the country's largest nuclear facility, the Palo Verde Nuclear Generating Station ("Palo Verde"). Palo Verde produces over 32 million megawatt-hours of power annually which serves more than four million people.[24] As shown below, the facility is jointly owned by APS, SRP, and others including El Paso Electric, Southern California Edison, PNM Resources, Southern California Public Power Authority and the Los Angeles Department of Water and Power ("LADWP").

Figure 4: Palo Verde Ownership[25]

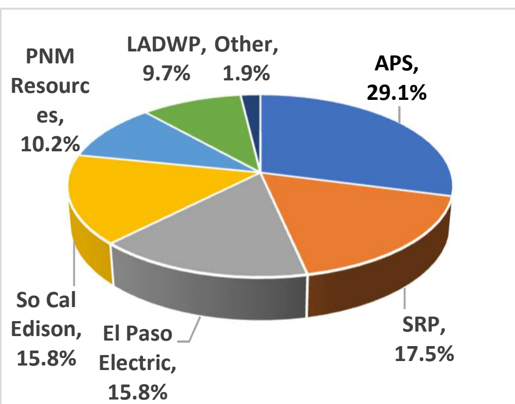


Figure 5: Generation Type (2017)[26]

Nameplate Capacity (MW)	Merchant	Regulated	Total
Combined Cycle	10,692.1	9,669.5	20,361.6
Gas Turbine	1,282.2	2,146.4	3,428.6
Hydraulic Turbine	2,718.0		2,718.0
Internal Combustion	12.4		12.4
Nuclear		63,144.0	63,144.0
Other	20.0	4.0	24.0
Pumped Storage	194.1		194.1
Solar	3,435.7	260.9	3,696.6
Steam Turbine	1,872.3	22,782.4	24,654.7
Wind Turbine	504.6		504.6
	20,731.4	98,007.2	118,738.6
	17.5%	82.5%	100.0%

22 SNL.
23 Ibid.
24 Palo Verde fact sheet, located at https://www.aps.com/library/resource%20alt/PV_FactSheet.pdf
25 SNL.
26 Ibid.

Although some interstate wholesale electricity transactions occur, wholesale markets are dominated by vertically integrated regulated utilities, which produce over 80% of the state's electricity.

Currently, APS participates in the Western Energy Imbalance Market ("EIM") operated by the CAISO. The EIM is a real-time only energy market that dispatches low-cost energy to serve real-time consumer demand across a wide geographic area. SRP will begin participation in the EIM starting 2020 and TEP will follow in 2022.

To meet customer demand, the state's two largest IOUs – TEP and APS – procure electricity produced both in and outside of the state. The figures reported above do not include some Arizona-based generation that serves out-of-state customers and excludes other out-of-state resources, including renewable power systems, that serve Arizona customers. The figures below depict the companies' resource mixes, which include generation from coal, natural gas, renewables, as well as market purchases.

Figure 6: TEP's Portfolio Energy Mix 2017 and 2032[27]

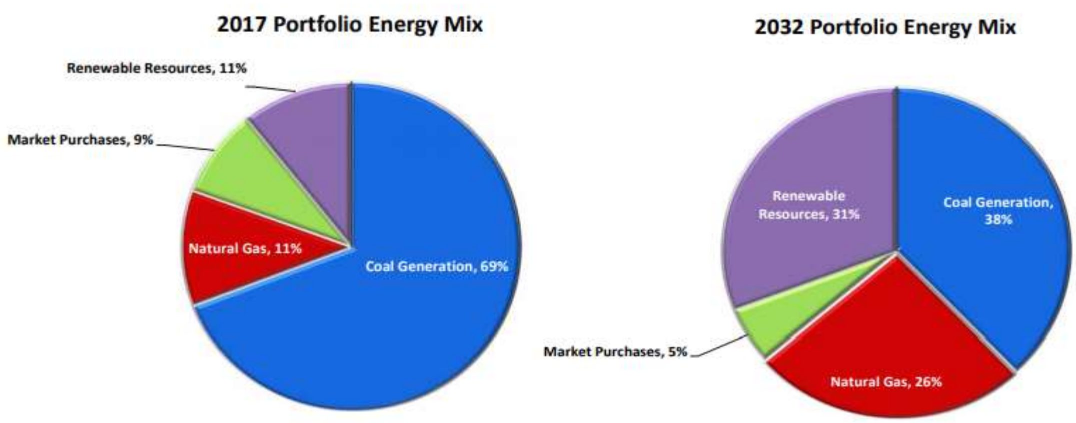
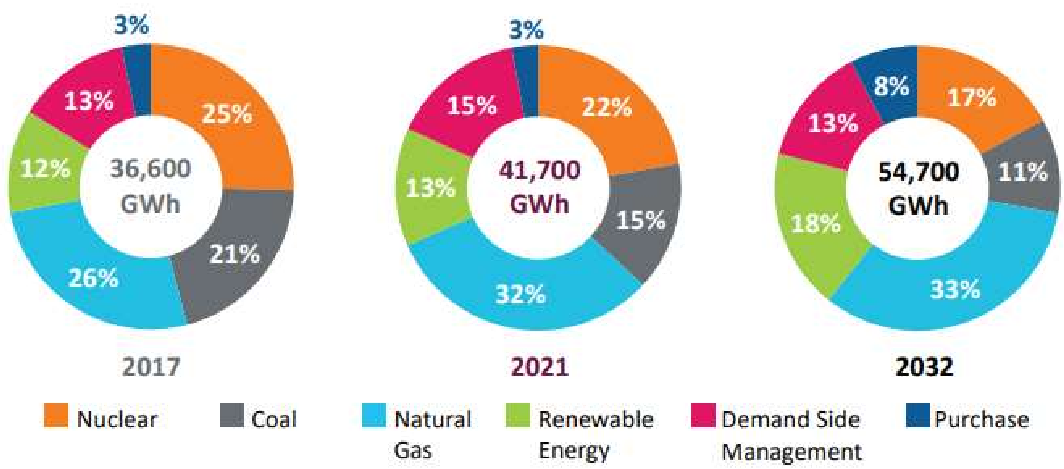


Figure 7: APS Energy Mix of the 2017 IRP Selected Plan[28]



27 TEP Integrated Resource Plan, 2017 (https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf).

28 APS Integrated Resource Plan, 2017

C. History of Electric Restructuring in Arizona

Arizona has considered retail electric restructuring initiatives in recent decades:[29]

- After five years of workshops, the ACC established final rules in 1999 that would have phased in full retail competition for each IOU by January 1, 2003. In 2002, due primarily to a lack of competitive suppliers in the state and extensive issues in California's restructuring efforts, the commission retracted the directives that had previously mandated that the state's electric utilities transfer their generating assets to unregulated affiliates, and that they must procure at least 50% of all power requirements through competitive bidding by January 1, 2003.
- While retail competition was still permitted after this ruling, the Arizona Court of Appeals in 2004 invalidated many provisions of the ACC's competition rules. ("Phelps Dodge Decision[30]")
- In 2008, several entities filed applications at the ACC, seeking reconsideration. This resulted in a 2010 Staff report that stated that the rules are incomplete.
- In May 2012, APS put into place an "Experimental Rate Service Rider Schedule" which permitted third-party power providers to offer wholesale power to APS on behalf of specific customers. Through the rate schedule, which was part of a settlement agreement, APS purchases and manages generation on behalf of certain large use customers. The program is capped at 200 MW, and applicants are required to aggregate into a 10 MW group. The program is fully subscribed.
- In May 2013, the ACC opened a generic docket (Docket No. E-00000W-13-0135) to explore the possibility of restructuring given the Commission's regulatory authority in relation to the Phelps Dodge decision. The Commission concluded on September 11, 2013 that the Phelps Dodge decision indicates that the Commission lacks the necessary level of Constitutional authority to order market restructuring or asset divestiture. Janice Alward, the Legal Division Chief Counsel at the ACC, at the time stated that "the Commission would face substantial legal challenges related to the very clear language of Phelps Dodge that raises the barrier of fair value requirement in a meaningful way when you set rates under your constitutional Section 3 authority. I think Phelps Dodge says market rates in and of itself are not constitutional." The Commissioners voted 4 – 1 to conclude the investigation, which was officially closed on October 7, 2013.[31]
- On August 17, 2018, the ACC opened a new docket (Docket No. RU-00000A-18-0284) to explore a wide range of energy rules primarily focused on renewables but also listing "Retail Electric competition" as a potential item for discussion. A December 3, 2018 ACC workshop resulted in concurrence among the commissioners that a new docket should be opened. As of July 10, 2019, the Commission is still in the process of receiving feedback from residents on these issues.[32]

(https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf).

29 S&P Global.

30 MARICOPA County Superior Court Decision No. CV1997-03748, March 15, 2004.

31 Arizona Corporation Commission, DOCKET NO. E-00000W-13-0135, In the Matter of the Commission's Inquiry into Retail Electric Competition.

32 Arizona Corporation Commission, Request for a New Docket – In the Matter of Modifications to the Commission's Energy Rules, Docket RU-00000A-18-0284, August 17, 2018.

- On May 3, 2019, ACC Chairman Burns announced that the commission would be holding additional workshops on retail electric competition (Docket No. RE-00000A-18-0405).[33] Chairman Burns stated that he would like the following topics, at a minimum, addressed:
  - CCA for groups such as HOA, developments without HOAs, neighborhood community groups, special districts, etc.
  - Microgrids being able to operate independently of the interconnected grid in the event of an outage (accidental, planned, or natural disaster) on the interconnected grid.
- The next workshop is scheduled for July 2019.

D. Arizona Independent Scheduling Administrator Association

When Arizona was originally contemplating full restructuring, the state established its own market operator, the Az ISA in 1998. The stated purpose of the Az ISA is to "facilitate open, non-discriminatory transmission access to support implementation of retail electric competition in the State of Arizona."[34] Although the Phelps Dodge decision invalidated the ACC's authority to create the Az ISA, the Az ISA still exists today but is essentially inactive waiting for further development of restructuring in the state.

E. Municipalities, Cooperatives, and Tribal Systems

As noted above, approximately 10% of Arizona's electric demand is served by municipalities, cooperatives and tribal systems. Traditionally, these entities are exempt from restructuring. In Texas, for example, municipalities and cooperatives were allowed to "opt out" of the state's restructuring plan.[35]

[33] https://docket.images.azcc.gov/E000000700.pdf
[34] Arizona Independent Scheduling Administrator Association. http://az-isa.org/
[35] Texas Senate Bill 7.

IV. Regulation and Restructuring

A. Regulated v. Restructured Electric Markets

The terminology "Restructured", "Deregulated", "Competitive" – all imply less or different regulation. As context for this report, the general nature of electric regulation in a traditionally regulated market versus a restructured market is described below.

In a traditionally regulated market, electricity is supplied by vertically integrated regulated utilities (or city-owned or municipal electric companies, or cooperatively owned utilities). These utilities own and/or contract for generation, and own and operate transmission and distribution and provide electricity to customers within specific service territories at regulated rates established by state regulators. Rates are largely established on a cost-of-service basis and utilities are provided the opportunity to earn a reasonable, regulated return on the investments they make on behalf of their customers. With regard to generation in particular, state regulators review and approve the recovery of costs for utility-built and contracted for generation. As discussed in Chapter VI, state regulators may review and approve long-term resource plans evaluating the needs of customers and the resources that will be used to meet those needs. The prices paid by a utility's customers for generation are a function of the approved generation mix and prices of underlying fuels (e.g., coal, oil, natural gas, etc.).

In a restructured market, regulated utilities continue to provide transmission and distribution service at regulated rates. Generation service, however, is no longer rate regulated. Instead, the rates paid by customers are those offered by unregulated retail electricity suppliers or, for customers who do not receive service from competitive suppliers, utility provided POLR service that is reflective of wholesale market prices. State regulators no longer review and approve long-term resource plans or the cost of generation.[36] Independent market monitors provide oversight to ensure fair trade practices but not rate regulation. Reducing the price paid by retail customers for generation was a key driver of state restructuring initiatives.

During the initial years of electric market restructuring, several economic policy papers outlined the restructured electric market model. For example:

> *Electricity market restructuring emphasizes the potential for competition in generation and retail services, with operation of transmission and distribution wires as a monopoly. Network interactions complicate the design of the institutions and pricing arrangements for open access to the wires. The design of the institutions for the wholesale market can accommodate access for both wholesale and retail competition while recognizing the special requirements of reliability in the transmission grid.*

[36] States may review the cost of POLR or default service.

A pool-based, short-term electricity market coordinated by a system operator provides a foundation for building an open access system. Coordination through the system operator is unavoidable, and a bid-based spot-market built on the principles of economic dispatch creates the setting in the wholesale market for competition among the market participants. The associated locational prices define the opportunity costs of transmission usage and support transmission rights without restricting the actual use of the system. A system of contracts can provide the connection between short-term operations and long-term investment built on market incentives.[37]

B. The Role of State Regulators

The role of state regulators in a restructured electricity market with full retail competition is very different than it is in a traditionally regulated market. While state regulators still have oversight over the IOUs providing regulated utility distribution service within their jurisdiction, the more limited role of these IOUs providing no or only default generation service likewise limits the role state regulator.

Utilities in a traditionally regulated market have an obligation to serve their customers, including designing, building or procuring energy, with rates approved and overseen by their state regulatory commission. In a restructured market, this obligation and oversight is eliminated as it pertains to generation or energy service (but for POLR or default service). The role of state regulators in a restructured energy market is primarily focused on delivery service. The state regulators (and policy makers) must now shift to exerting influence through FERC proceedings.

In many traditionally regulated states, state commissions review integrated resource plans prepared by IOUs, which evaluate the energy needs of their customers and how best to meet those needs. State regulators no longer oversee resource plans in restructured markets but continue to have siting authority over new power plants.

State regulatory commissions also implement public policy through their regulation of electric utilities. For example, many states have implemented renewable portfolio standards requiring IOUs to include a certain amount of renewable generation in their supply portfolios. In a restructured market, state regulators have much less influence over the resources that serve the state’s citizens and limited ability to implement public policy.

State regulators role post-restructuring (i.e., among other roles that may not change) may include:

- Jurisdiction over retail rates for electric delivery service only;
- Continued siting authority but no authority regarding resource planning;
- Taking enforcement actions against energy service providers that do not comply with state rules;
- Reviewing applications from competitive suppliers for licensure and issue certificates;
- Reviewing applications from retail providers to cease providing service;
- Overseeing transition of customers from retail providers that exit the market;
- Overseeing POLR programs; and
- Addressing questions/complaints from customers to the commission.

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[37] “Competitive Electricity Market Design: A Wholesale Primer” by William W. Hogan, December 17, 1998.

C. Role of Federal Regulators

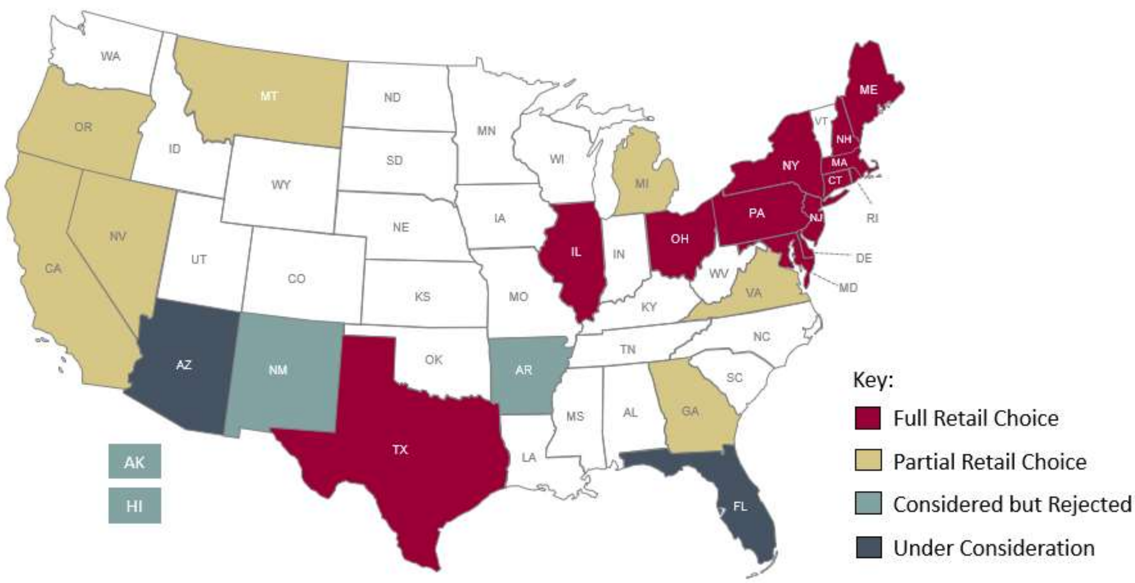
Among other things, FERC has jurisdiction over the large-scale transmission system (e.g., 69 kilovolt and above), under the principle that it constitutes interstate commerce and is therefore subject to federal jurisdiction under the U.S. Constitution. Likewise, FERC has jurisdiction over wholesale power sales. Moreover, when a wholesale market is restructured, overall system planning of the bulk power system (transmission and generation) is under the purview of the ISO or RTO, which is subject to federal jurisdiction. FERC specifically does not have jurisdiction over the sale of electricity to end users (i.e., sales at retail) and the rates, terms and conditions of such sales. FERC also does not have oversight over what generation gets built.

V. Survey of U.S. States

A. Introduction

Twenty-five states have considered electric restructuring, and twenty-one have implemented some form of electric retail competition. Retail competition in these states ranges from full competition of generation supplier for all retail customers (commercial, industrial and residential) to partial retail competition available up to a capped amount for industrial customers only. Figure 8 highlights the status of electric restructuring nationwide.

Figure 8: Electric Restructuring State Map[38]



B. States with Full Retail Competition

Fourteen states have implemented full retail competition for all customers of IOUs. Table 2 summarizes these states. The column "Implementation Timeframe" in Table 2 reflects the period over which restructuring was implemented in the state. It is noteworthy that for many states the period was quite lengthy, reflecting challenges in implementation.

Table 2: States with Full Retail Competition

State	Legislation/ Regulation	Citation	Implementation Timeframe	Summary
Connecticut	Legislation	Public Act 98-28, An Act Concerning Electric Restructuring	1998-2003	Retail competition for all IOU customers was implemented in 1998.

[38] Adapted from American Coalition of Competitive Energy Suppliers. http://competitiveenergy.org/

State	Legislation/ Regulation	Citation	Implementation Timeframe	Summary
Delaware	Legislation	Electric Utility Restructuring Act of 1999	1999-2006	Retail competition for all IOU customers was implemented in 1999.
District of Columbia	Regulation, Legislation	Formal Case No. 945, Order No. 11628 and Bill 13-284: Retail Electric Competition and Consumer Protection Act of 1999	1999 -2005	Retail competition for all IOU customers was implemented in 2001.
Illinois	Legislation	Electric Service Customer Choice and Rate Relief Law Of 1997	2002-2007	Retail competition for all IOU customers was implemented in 1997.
Maine	Legislation	Revised Maine Statutes Annotated, Title 35-A	1997-2000	Retail competition for all IOU customers was implemented in 2000.
Maryland	Legislation	Electric Customer Choice and Competition Act of 1999	2000-2008	Retail competition for all IOU customers was implemented in 1999.
Massachusetts	Legislation	An Act Relative to Restructuring the Electric Utility Industry in The Commonwealth, Regulating the Provision of Electricity and Other Services, And Promoting Enhanced Consumer Protections Therein. Chapter 164	1997-1999	Retail competition for all IOU customers was implemented in 1998.
New Hampshire	Legislation	Electric Utility Restructuring Act, RSA 374-F	1998-2018	Retail competition for all IOU customers was implemented in 1998. Public Service of New Hampshire ("PSNH") divested its generation assets and exited the generation market in 2018. 20 years after restructuring was first introduced.

State	Legislation/ Regulation	Citation	Implementation Timeframe	Summary
New Jersey	Legislation	Electric Discount and Energy Competition Act	1999-2003	Retail competition for all IOU customers was implemented in 1999.
New York	Regulation	CASES 94-E-0952 et al. OPINION NO. 96-12	1996-1998	Retail competition for all IOU customers was implemented in 1997.
Ohio	Legislation	Amended Substitute Senate Bill No. 3 of the 123rd General Assembly, Section 4928.31, Revised Code	1999-2008	Retail competition for all IOU customers was implemented in 1996.
Pennsylvania	Legislation	Electricity Generation Customer Choice and Competition Act	1996-2011	Retail competition for all IOU customers was implemented in 1997.
Rhode Island	Legislation	Utility Restructuring Act of 1996	1996-1998	Retail competition for all IOU customers was implemented in 1996.
Texas	Legislation	S.B. 7 - Electric Restructuring, Section 11.003	1999-2006	Retail competition for all IOU customers was implemented in 2002.

C. States with Partial Retail Competition

Seven states have implemented partial retail competition, in some cases starting with full retail competition and ultimately re-regulating portions of the state's electricity markets. These states include California, Georgia, Michigan, Nevada, Oregon, Virginia, and Montana.

1. California

In 1996, California became one of the first states to restructure its energy market. The Electric Utility Industry Restructuring Act that restructured California's electricity industry was intended to lower electricity prices for the state's electricity consumers. Restructuring plans that included the implementation of retail electricity price caps for customers of the state's three large IOUs (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric) were implemented.

By the summer of 2000, demand for electricity had outpaced the generating capacity available to supply the market and wholesale electricity prices were rising. In April 2000, wholesale electricity prices were approximately $30/MWh. By November 2000, prices had increased to between $250 MWh and $450 MWh.[39] FERC ordered a soft price cap on wholesale markets to limit price changes while allowing cost-based price increases above the wholesale price-controlled levels. These soft caps were not effective and eventually, FERC ordered large refunds from retail marketers to California in light of market abuses by Enron and other marketers.

[39] ASU Energy Policy Innovation Council, October 2013.

In 2001, the California grid operator was forced to institute statewide rolling blackouts. Emergency rate increases were implemented but they were insufficient to protect the financial assets and the credit worthiness of the state's large IOUs. Pacific Gas & Electric eventually filed for bankruptcy.

The California Public Utilities Commission ("CPUC") suspended retail competition on September 20, 2001, in Decision 01-09-060. Currently, there is limited access to competitive electricity.

2. Georgia

New customer locations with a connected load of over 900 kilowatt ("kW") have had the choice of their electric supplier since 1973.[40] In 1997, the Georgia Public Service Commission ("GPSC") began an investigation into electric restructuring. After four public hearings, the GPSC issued its final report in January 1998.[41] The report stated that its purpose was to inform the Georgia General Assembly on the establishment of new laws. The report did not provide a final determination on whether restructuring would prove beneficial to Georgia, but rather set a list of guiding principles and suggested creating several dockets to explore restructuring. As a result of the report, five focus groups were established to cover the array of topics that would need to be addressed if restructuring were to move forward.[42] After these focus group reports were issued, the GPSC took no further action, and the Georgia General Assembly did not pursue restructuring laws.

3. Michigan

Michigan Public Act 141, known as the "Customer Choice and Electric Reliability Act," mandated competition for all retail customers of IOUs by January 1, 2002 and required an immediate five percent rate reduction and a rate freeze until at least January 1, 2006 for residential customers of Consumers Energy and Detroit Edison. The law directed the three largest utilities in the state[43] to file a joint plan by January 1, 2002. The plan was to address how to permanently expand available transmission capacity by at least 2,000 MW by 2004. Additionally, the law directed all utilities serving the state to immediately take "all necessary steps" to connect merchant power plants with more than 100 kW to their T&D systems. Utilities were also required to relinquish commercial control over any generation that exceeded 30% of relevant market capacity. Under the implementation rules approved by the Michigan Public Service Commission, customers that failed to choose an alternative supplier, or that were not offered service from another supplier, would receive service from their existing utility. In addition, Public Act 141 imposed certain other protections for residential customers, including winter shut-off protections for senior citizens and low-income customers.

Few customers switched electricity suppliers due to a variety of reasons including high wholesale prices and low retail price caps, and competitive choice of suppliers. In 2008, the governor of Michigan capped participation in electric competition programs, guaranteeing utilities a 90% market share, in exchange the utilities committed to deploy more renewable energy.

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[40] S&P Global Market Intelligence, Multiple Commissions - Electric Regulatory Reform/Industry Restructuring. December 19, 2016.

[41] Georgia Public Service Commission, Commission Role in Electric Restructuring. Accessed May 31, 2019, http://www.psc.state.ga.us/electric/crstructure.asp

[42] The topics covered by the focus groups included: Principles to Be Considered in A Changed Electric System, Stranded Cost, Statutory Changes, System Operations in A Restructured Electric Industry and Tax Implications of Restructuring Georgia's Electric Industry. See: http://www.psc.state.ga.us/electric/crstructure.asp.

[43] Consumers Energy, Detroit Edison, and Indiana Michigan Power Company

4. Nevada

Nevada took its first official legislative steps towards restructuring its electricity markets in a 1995 resolution Assembly Concurrent Resolution ("ACR") 49. ACR 49 directed the Public Service Commission to study the impacts of restructuring in Nevada. The PSC accordingly created a report titled "The Structure of Nevada's Electric Industry: Promoting the Public Interest."[44] In 1997, Assembly Bill 366 was passed, which established the foundations for restructuring. This bill stipulated that retail access would begin no later than December 31, 1999. In 1999, Senate Bill 438 was passed, which amended portions of AB 366 and expanded the language on POLR. The bill additionally pushed commencement date out to March 1, 2000.[45] In 2000, the Governor announced that the commencement date would be further pushed back to no later than September 1, 2001. At this time another report was commissioned to develop a long-term strategy for restructuring in the state, this report was submitted in January 2001. In February 2001, the Governor announced the Nevada Energy Protection Plan which put an indefinite halt on retail restructuring in Nevada.[46] Finally, AB 369 returned the utilities back to the traditional vertically-integrated structure in April 2001.[47] AB 661 was released shortly after in July 2001, allowing large customers (those using 1 MW or more annually) to choose their electric supplier if they received permission from the Commission.[48]

Recently, a statewide ballot initiative was introduced to provide retail competition for all customers. The statewide ballot initiative went before voters in both the November 2016 and 2018 general elections. After significant time and expense, the voters of Nevada decided not to move forward with restructuring.

5. Oregon

Senate Bill 1149 was signed into law in July 1999, requiring Portland General Electric and PacifiCorp to offer their customers energy options. The law did not require utilities to divest their generation assets and adopted a host of other consumer protections. The consumers were not forced into the competitive market but were given the choice of entering the competitive market or receiving a regulated cost of service rate from the utility. Residential and small non-residential customers (those consuming under 30kW monthly) receive a portfolio of energy options from the utilities. Customers with over 30kW in monthly usage can purchase electricity from an Electricity Service Supplier.[49]

6. Virginia

In 1999, the Virginia General Assembly passed a law, Senate Bill 1269,[50] that was intended to restructure Virginia's electricity markets. After several years, the General Assembly determined that

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44 Public Utilities Commission of Nevada, Historic Overview: Nevada Deregulation 1990's, November 7, 2017, page 4. http://energy.nv.gov/uploadedFiles/energynvgov/content/Programs/TaskForces/2017/11-07-2017_EnergyChoice_Agenda6_PUCN%20Presentation.pdf

45 *Id.*, page 5.

46 *Id.*, page 22.

47 *Id.*, page 23.

48 Nevada Assembly Bill 661, July 2001, https://www.leg.state.nv.us/71st/bills/AB/AB661_EN.html

49 Public Utility Commission of Oregon, "Restructuring Law SB 1149." Accessed June 2, 2019, https://www.puc.state.or.us/Pages/electric_restruc/consumer/summary.aspx

50 Senate Bill 1269, 1999 Session, An Act to amend the Code of Virginia by adding in Title 56 a chapter numbered 23, consisting of sections numbered 56-576 through 56-595, relating to the Virginia Electric Utility Restructuring Act.

insufficient competition had developed, primarily due to high gas prices and low retail rates, and in 2007, the General Assembly passed a comprehensive re-regulation law, Senate Bill 1416.[51] and House Bill 3068.[52] Currently, only customers using at least 5 MWh a year or any customer that will use 100% renewable energy can buy electricity from a company other than the regulated utility.

7. Montana

In 1997, the Montana legislature passed an electric restructuring bill Senate Bill No. 390, "An Act generally establishing restructuring requirements for Montana's electric utility industry." Montana Power sold its electric generating assets as well as a portion of its distribution assets in Docket No. D97.7.90, with a final order being issued on January 31, 2002.[53] By the summer of 2003, electricity prices in Montana had risen by 15%.[54] In 2007, the legislature passed the "Electric Utility Industry Generation Reintegration Act" to reverse restructuring efforts in the state. The state's power companies were allowed to purchase generation, and, with limited exceptions, retail competition was suspended.

D. States that Considered but Rejected Restructuring

Alaska, Arkansas, Hawaii, and New Mexico actively considered retail competition but ultimately chose not to restructure their electricity markets.

1. Alaska

The Regulatory Commission of Alaska ("RCA") studied the potential impacts of restructuring in the state starting in 1997 and concluded its review in 2001. The RCA retained CH2M Hill, Inc.[55] (a private consulting firm) to create a study on the impacts of restructuring on Alaska. After receiving the report, the RCA concluded that the results of restructuring were "too speculative" to move forward.[56] The report proposed to gradually introduce restructuring to Alaska but only along the Railbelt region and not within rural areas. The report also considered Alaska's move to a partially restructured state to be "inevitable."[57] The RCA disagreed stating that given they do not have any interconnections with other states they are not bound "to respond to the actions of its neighbors."[58]

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[51] SB 1416 Electric utility service; advances scheduled expiration of capped rate period. Accessed June 2, 2019, https://lis.virginia.gov/cgi-bin/legp604.exe?071+sum+SB1416

[52] HB 3068 Electric utility service; advances scheduled expiration of capped rate period. Accessed June 2, 2019, http://leg1.state.va.us/cgi-bin/legp504.exe?ses=071&typ=bil&val=hb3068

[53] Montana Public Service Commission, Docket D97.7.90, Order 5986w, January 31, 2002.

[54] Great Falls Tribune, December 6, 2014.

[55] CH2M HILL, Inc. provides design-build, consulting, project management, program management, operations management, construction management, and design consulting services to governments, cities, transportation, water, environment, nuclear, energy, and industry sectors in the United States. In addition, it designs infrastructure and master plans for campuses or entire regions, office buildings, laboratories, or manufacturing plants; and develops business and sustainability solutions that solve environmental and socioeconomic issues. https://www.bloomberg.com/research/stocks/private/snapshot.asp?privcapid=24912511

[56] Regulatory Commission of Alaska, Matter R-97-10 Order No. 8. September 28, 2001, page 1.

[57] Regulatory Commission of Alaska, Matter R-97-10 Order No. 8. September 28, 2001, page 4.

[58] Regulatory Commission of Alaska, Matter R-97-10 Order No. 8. September 28, 2001, page 4.

2. Arkansas

Arkansas' Electric Consumer Choice Act of 1999 (Act 1556 of 1999) mandated electric competition by January 1, 2002. As the California energy crisis unfolded, Arkansas legislators postponed open access. Shortly after the collapse of Enron Corporation, Arkansas regulators determined that continued movement toward retail competition was not in the public interest. On February 21, 2003, The Electric Utility Regulatory Reform Act (Act 204 of 2003) was passed, repealing the changes created by Act 1556.[59]

3. Hawaii

In 1996, the Hawaii Public Utilities Commission ("HPUC") instituted a regulatory proceeding to explore the potential of impacts of restructuring in the state. By 2003 the parties involved had not reached a consensus as to how approach restructuring in Hawaii. The HPUC concluded that it would watch how restructuring unfolded in other states before deciding how to proceed.

> *"Developments in other states indicate that, at best, implementation of retail access would be premature. In addition, projections of any potential benefits of restructuring Hawaii's electric industry are too speculative and it has not been sufficiently demonstrated that all consumers in Hawaii would continue to receive adequate, safe, reliable, and efficient energy services at fair and reasonable prices under a restructured market, at this time. Accordingly, the commission does not find it is in the public interest to completely restructure the electric industry at this time."*[60]

4. New Mexico

In 1999, New Mexico passed the Electric Utility Industry Restructuring Act of 1999 which required the utilities to separate into at least two companies (but not fully divest)[61] and institute full retail competition by January of 2002.[62] In November 1998, the New Mexico Public Regulation Commission ("NMPRC") issued an order that instructed the Public Service Company of New Mexico to unbundle its rates for Residential Electric, Incorporated. The Public Service Company of New Mexico argued that this would fundamentally be a restructuring of the electric industry in New Mexico. The NMPRC disagreed and stated that they viewed it well within their rights to order the unbundling of the utility's services.[63] In March 1999, the State Supreme Court ruled that the energy commission had exceeded its authority when it ordered Public Service of New Mexico to open its power lines to a competitor.[64] In April 2000, the New Mexico utilities requested that implementation of market competition be delayed as they were not prepared for the changes to billing. The NMPRC approved this request and moved the start date out to January 2002. In the wake of the restructuring crisis in California, in May 2001 Senate Bill 266 was enacted. This further pushed restructuring back to

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59 Arkansas Public Service Commission, Electric Section, Electric Restructuring. Accessed June 4, 2019, http://www.apscservices.info/electric.asp

60 Hawaii Public Utilities Commission, Docket No. 96-0493 Order No. 20584, October 21, 2003, page 5.

61 New Mexico Senate Bill 428, Electric Utility Industry Restructuring Act of 1999, page 18.

62 New Mexico Senate Bill 428, Electric Utility Industry Restructuring Act of 1999, page 11.

63 New Mexico Public Utility Commission, Cases 2867 and 2868, Final Order. November 30, 1998, page 2.

64 Electric Light and Power, State of Deregulation: N.M., Nev. looking to return their deregulation packages. June 1, 2001. https://www.elp.com/articles/print/volume-79/issue-7/departments/state-of-deregulation-nm-nev-looking-to-return-their-deregulation-packages.html

January 2007 with non-residential customers being pushed even further back to January 2008.[65] After the pushbacks the state eventually repealed the effects of Senate Bill 428 with Senate Bill 718 enacted in 2003. Senate Bill 718 additionally allowed companies to recover the costs they incurred in complying with Senate Bill 428.[66] New Mexico's electricity market continues to be fully regulated.

E. Active Restructuring Initiatives

As described above, Arizona is currently exploring issued related to electric retail competition.

In addition, earlier this year, an industry group, led by Infinite Energy, a wholesale and retail energy marketer, and supported by Walmart, started an initiative to include on Florida's 2020 ballot a measure entitled "Right to Competitive Market for Customers of Investor-Owned Utilities: Allowing Energy Choice." If passed, this ballot measure would amend the Florida state constitution to create a constitutional right to retail competition, among other things. Proponents summarize the constitutional amendment by describing it as such:

> *Grants customers of investor-owned utilities the right to choose their electricity provider and to generate and sell electricity. Requires the Legislature to adopt laws providing for competitive wholesale and retail markets for electricity generation and supply, and consumer protections, by June 1, 2025, and repeals inconsistent statutes, regulations, and orders. Limits investor-owned utilities to construction, operation, and repair of electrical transmission and distribution systems. Municipal and cooperative utilities may opt into competitive markets.*[67]

The process for Florida ballot measures includes the evaluation of the financial impact of the proposed measure on state and local governments by the state's FIEC. The FIEC convened in February and, as required, issued its financial impact statement and supporting materials 45-days later. Taken as a whole, the FIEC concluded that the proposed amendment would result in "significant costs to state and local government," and that "significant legal and litigation expenses are probable" among other factors.[68] The ballot measure is now at the Florida Supreme Court and a decision about whether the measure may be placed on the ballot if it receives the required number of signatures in support is expected in the fall.

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[65] Electric Light and Power, State of Deregulation: N.M., Nev. looking to return their deregulation packages. June 1, 2001. https://www.elp.com/articles/print/volume-79/issue-7/departments/state-of-deregulation-nm-nev-looking-to-return-their-deregulation-packages.html

[66] S&P Global Market Intelligence, Multiple Commissions - Electric Regulatory Reform/Industry Restructuring. New Mexico, January 2, 2015.

[67] FL Division of Elections, Right to Competitive Energy Market for Customers of Investor-Owned Utilities, Ballot Initiative Summary. https://dos.elections.myflorida.com/initiatives/initdetail.asp?account=73832&seqnum=1

[68] Florida Financial Impact Estimating Conference, Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice, Serial Number 18-10, March 15, 2019, page 1.

VI. Wholesale Market Considerations

A. Wholesale Market Elements

In order to implement retail restructuring, a functioning wholesale electricity market is necessary to facilitate the buying and selling of electricity for all retail customers. All states that have restructured their electricity markets to provide full retail competition (commercial, industrial and residential) are part of either an ISO or an RTO. ISOs/RTOs are not-for-profit entities that were formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs.

Wholesale electricity markets generally consist of an organized day-ahead and real-time market for energy. The day-ahead market allows for market participants to submit bids and offers for energy for next day delivery. These bids and offers reflect financial positions that generation and load serving entities "lock-in" prior to the operating day. The real-time market is a physical market in the operating day where the grid operator dispatches generation based on offers to supply energy and bids to consume energy. Prices paid by load and paid to generating resources are known as locational marginal prices ("LMPs"). LMPs reflect the value of electric energy at hundreds and sometimes thousands of different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. LMPs consist of an energy component (the price for energy), a congestion component (the marginal cost of congestion at a given location), and a loss component (the costs of system losses at a given location). The market is settled at the location-based LMP based on deviations between bids and offers in the day-ahead and real-time markets.

In addition to the markets for energy, there are markets for: i) capacity which represents an insurance policy for "steel in the ground" when needed; ii) ancillary services to ensure the system can reliably meet demand during unexpected system conditions; iii) transmission congestion and loss management tools; and iv) other financial mechanisms that allow for efficient market outcomes and risk management.

Oversight of the competitive wholesale markets is provided by FERC and the independent market monitor to ensure a competitive and nondiscriminatory electric power market. FERC ensures that the market supports competition and maintains a just and reasonable marketplace by enforcing the rules. In fulfilling these responsibilities, FERC approved market power mitigation protocols that gave the ISOs limited power to review and regulate generator offer prices under certain conditions. The protocols are enforced by the ISO's/RTO's market monitor.

B. Establishment of RTOs/ISOs

1. History

The history of the ISO/RTO dates back to FERC Orders 888 and 889, which suggested the concept of the independent system operator to ensure non-discriminatory access to transmission systems. FERC Order 2000 encouraged all transmission-owning entities to form or join such an organization to promote the regional administration of high-voltage transmission systems. FERC Order 2000 contained a set of technical requirements for any system operator to be considered a FERC-approved RTO, since RTOs are regulated by FERC, not by the states (i.e., RTO rules are determined by a FERC-approved tariff and not by state Public Utility Commissions).[69] Each RTO establishes its own rules and market structures, but there are many commonalities. Broadly, the RTO performs the following functions: i) management of the bulk power transmission system within its footprint; ii) ensuring non-discriminatory access to the transmission grid by customers and suppliers; iii) dispatch of generation assets within its footprint to keep supply and demand in balance and administration of the entirety of the wholesale markets; and iv) regional planning for generation and transmission. In many ways, ISOs/RTOs perform the same functions as the vertically integrated utilities that were supplanted by electricity restructuring. There are, however, a number of important distinctions between ISOs/RTOs and utilities: i) ISOs/RTOs do not sell electricity to retail customers; ii) ISOs/RTOs purchase power from generators, resell it to electric distribution utilities, who then resell it again to end-use customers; iii) ISOs/RTOs may not earn profits; iv) ISOs/RTOs do not own any physical assets – they do not own generators, power lines or any other equipment; v) ISO/RTO decision-making is governed by a "stakeholder board" consisting of various electric sector constituencies. In some cases, the RTO can implement policy unilaterally without approval by the stakeholder board, but this is rare. Generally, however, policies must be approved by FERC; and vi) ISOs/RTOs monitor activity in their markets to avoid manipulation by individual generators or groups of generators.

C. Timing and Steps to Create an ISO/RTO

As shown in Table 3 the establishment of the ISOs/RTOs is an evolutionary process and takes many years to complete.

Table 3: ISO/RTO Development over Time

ISO/RTO	Timeline
CAISO[70] (CA)	The California ISO was created in September 1996 as a nonprofit public benefit corporation with the passage of California Assembly Bill 1890 that restructured the state's power market. It incorporated in May 1997 and in March 1998 began serving 80% of the state, or 30 million people, with the purpose of managing the state's transmission grid, facilitating the spot market for power and performing transmission planning functions. The California Power Exchange operated the state's competitive wholesale power market and customer competition program until the 2000-2001 energy crisis forced it into bankruptcy in January 2001. The exchange ultimately ceased operation leaving the state without a day-ahead energy market until spring 2009 when the ISO opened a nodal market.
ERCOT[71] (TX)	Formed in 1970, established as an ISO in 1996, with certain market protocols established by 2000. In 2001, wholesale power sales between electric utilities began as the existing 10 control areas in ERCOT consolidated into one. In 2002, retail electric markets opened. A nodal market, featuring locational marginal pricing for generation at more than 8,000 nodes was finally launched in 2010 after over six years of planning.

[69] FERC Order 2000 required that an RTO: i) operate independently from market participants; ii) serve a region of sufficient scope and configuration to permit it to maintain reliability, effectively perform its required functions, and support efficient and nondiscriminatory power markets; and iii) have exclusive authority for maintaining the short-term reliability of the grid.

[70] California Independent System Operator Corporation, 2010 ISO/RTO Metrics Report, Appendix D, page 28.

[71] History of ERCOT, http://www.ercot.com/about/profile/history.

ISO/RTO	Timeline
SPP[72] (AR, IO, KS, LA, MN, MT, MO, NM, ND, OK, SD, TX, WY)	Formed in 1941, SPP joined the National Energy Reliability Corporation ("NERC") in the 1960s. SPP implemented a regional open-access tariff in 1998. The tariff provided non-firm and short-term firm, point-to-point transmission service across the systems of 14 members. Long-term firm service followed in 1999 and network service in 2001. It took SPP several attempts before FERC gave it RTO status in 2004. In 2007, SPP implemented the Energy Imbalance Service, which took two years to put in place at a cost of $33 million.
MISO[73] (AR, IL, IN, IO, KY, LA, MI, MN, MS, MO, MT, TX, WI)	MISO was initially established in 1998. FERC accepted MISO's organizational plan and initial transmission tariff on Sept. 16, 1998, then approved the MISO as an RTO in December 2001. On April 1, 2005, MISO launched the Energy Markets and began centrally dispatching generating units throughout much of the central United States based on bids and offers cleared in the market.
PJM[74] (DE, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, VA, WV, DC)	Founded in 1927 as a power pool, PJM opened its first bid-based energy market on April 1, 1997. Later that year, FERC approved PJM as an ISO. In 2000, PJM launched both a market for regulation service, its first ancillary services market, and the Day-Ahead Energy Market. PJM became an RTO in 2001. From 2002 through 2005, PJM integrated several utility transmission systems into its operations. They included: Allegheny Power in 2002; Commonwealth Edison, American Electric Power and Dayton Power & Light in 2004; and Duquesne Light and Dominion in 2005. These integrations expanded the number and diversity of resources available to meet consumer demand for electricity and increased the benefits of PJM's wholesale electricity market. In 2007, PJM completed its first capacity auction under the Reliability Pricing Model which secures power supply resources for the future.
NYISO[75] (NY)	The creation of the NYISO was authorized by FERC in 1998. In November 1999, New York State's competitive wholesale electricity markets were opened to utility and non-utility suppliers and consumers as the NYISO began its management of the bulk electricity grid. The formal transfer of the grid operation responsibilities from the New York Power Pool to the NYISO took place on December 1, 1999. NYISO studied the implementation of a forward capacity market but did not implement this market change.
ISO-NE[76] (CT, MA, ME, NH, RI, VT)	The New England Power Pool was established in 1971. In 1997, ISO New England ("ISO-NE") was created to operate the regional power system, implement wholesale markets, and ensure open access to transmission in New England. In 1999 ISO-NE launched a regional wholesale electricity market to expand its competitive market to regional generation and sales of wholesale electricity. In 2003 ISO-NE added locational pricing, day-ahead and real-time markets to more accurately reflect the cost of wholesale power and provide clearer economic signals for infrastructure investment. In 2005, ISO-NE began operation as an RTO assuming broader authority over day-to-day operation of region's transmission system. In 2006, ISO-NE launched a forward reserve market for better valuation of reserves. In 2008, ISO-NE launched a new Forward Capacity Market to replace the old ICAP market.

72 The Power of Relationships, 75 Years of Southwest Power Pool, Nathania Sawyer and Les Dillahunty, 2016.
73 Midwest Independent Transmission System Operator, 2010 ISO/RTO Metrics Report, Appendix E, at 144. MISO History, https://www.misoenergy.org/stakeholder-engagement/learning-center/miso-history.
74 PJM Interconnection, 2010 ISO/RTO Metrics Report, Appendix H, page 260.
75 New York Independent System Operator, 2010 ISO/RTO Metrics Report, Appendix G, page 196.
76 New England Independent System Operator, Our History, https://www.iso-ne.com/about/what-we-do/history.

As highlighted above there are numerous steps required to form an RTO, with many regulatory approvals along the way, including:[77]

- Negotiations among the various stakeholders on operating protocols and RTO structure (a year or longer);
- Filing and approval with FERC (six to eighteen months);
- Additional FERC filings to transfer operational control of transmission assets (at least six months);
- Modifications to existing transmission Open Access Transmission Tariffs (twelve months or longer);
- Additional approvals from other reliability governing bodies (six months or longer);
- Once approved, developing operating systems, policies and staffing (a year or longer); and
- Development of an internal market monitoring function and retention of a qualified independent market monitor to identify and report market violations, market design flaws and market power abuses.

In addition, all the following must be addressed when designing the market and determining competition rules:

- <u>Capacity, ancillary and energy markets</u>: Rules and rates must be established to set up each of these markets and trading policies.
- <u>POLR:</u> Rates and rules must be set for the POLR, the provider who must serve a customer when another provider defaults or drops a customer. This includes determining who the POLR would be.
- <u>Generation divestiture</u>: Existing utilities may be required by restructuring rules to sell off or spin off their power generation business.
- <u>Stranded costs</u>: A process must be put in place for existing utilities to recover investments made in power plants. Stranded costs are then recovered from customers on their bills.
- <u>Systems and Processes</u>: Computer information systems and cybersecurity protocols must be established and procedures for switching customers to and from retail suppliers must also be established.

D. Cost of Implementing an ISO-RTO

Estimates of the cost to form an RTO/ISO range from $100 million to upwards of $500 million. Additionally, full implementation could take up to ten years.

Most recently, the Nevada Governor's Committee on Energy Choice asked the PUCN to open an investigatory docket to examine issues related to Nevada's Energy Choice Initiative. The PUCN finalized the Energy Choice Initiative Final Draft Report ("PUCN Report") in April 2018. The PUCN Report noted the following:

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77 For the most part these steps are dependent on the previous approval.

> *NV Energy states that a Nevada-only ISO would have new operational and administrative costs that would be paid by all Nevadans. NV Energy estimates that it would cost approximately 100 million dollars in new investment for NV Energy to set up a Nevada-only ISO wholesale market. This estimate does not include ongoing annual costs to operate the wholesale market.*
>
> *****
>
> *NV Energy estimates it will take 6 to 10 years to fully establish a Nevada-only ISO. This estimate is based on Nevada stakeholders needing one year or more to establish governance and a process to identify a market operator. This step could be shortened if the Nevada State Legislature designates NV Energy to perform the system and market operator functions. Thereafter, two to three years would be needed for a stakeholder process to establish the complex tariff for rules, price formation, and settlement formulas needed for the wholesale market operation systems. Like Nevada joining CAISO, FERC approval would be necessary.*[78]

In addition, the PUCN Report noted that there would be ongoing costs associated with operating and maintaining the new ISO/RTO. Specifically, the PUCN Report stated that, "Adding up these yearly maintenance costs totals approximately 45.7 million dollars…"

In 2017, the CAISO formed the "Committee on Energy Choice Technical Working Group on Open Energy Market Design & Policy." The President and CEO, Steve Berberich, presented findings from the Committee that concluded that "creating a new ISO could cost upwards of $500 million." He also noted that when the CAISO nodal market went live in 2009, it cost approximately $200 million and the Texas nodal market cost $600 million.[79]

In 2004, FERC studied the cost of developing an ISO/RTO. The Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization ("FERC RTO Cost Report") was written to:

> *…inform the Commission and facilitate discussions with the industry and the states regarding Regional Transmission Organization (RTO) formation. Specifically, the purpose of this Study is to estimate the cost of developing a Day One RTO that provides independent and non-discriminatory transmission service and satisfies the minimum requirements of Order No. 2000 to operate as an RTO. Further, the Study estimates the annual operating expenses necessary to run such an organization. Estimates of the costs of RTO formation vary widely and market participants cite the cost of RTO development as a significant barrier to RTO formation.*

FERC concluded that the Day-1 RTOs required investments of between $38 million to $117 million, which converts to 2018 dollars of $54 to $167 million.

Day-1 RTO costs only include the following: 1) administration of open access transmission tariffs; 2) performance of reliability functions and transmission planning; and 3) management of transmission through traditional methods, such as redispatch and transmission loading relief. Day-2 RTO costs include the administration of the same functions as Day-1 RTOs but also include costs associated with market operations for day-ahead and real-time energy, and for transmission congestion. In addition, many Day-2 RTOs operate ancillary services markets and capacity markets. The cost to implement a

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[78] Energy Choice Initiative Final Draft Report, Public Service Commission of Nevada, April 2018, pages 79-80.

[79] California ISO, Committee on Energy Choice Technical Working Group in Open Energy Market Design & Policy, July 10, 2017. Nodal ERCOT Program Update from November 2010, noted cumulative actual and forecast costs for the nodal program of $526.1 million.

Day-2 RTO is much higher since there are additional systems that must be added for day-ahead and capacity and ancillary services markets. In order to achieve the promised benefits of full retail reform, a functioning day-2 electricity market is necessary to facilitate the buying and selling of electricity for all retail customers.

The actual implementation costs for the development of the ISOs/RTOs noted above are difficult to calculate since they were developed, in some cases, over several years or decades through many different iterations.

E. Other Annual Costs

In addition to upfront implementation costs, there are on-going annual costs to administer an ISO or RTO. Those costs include, but are not limited to, salaries and benefits for employees, IT costs, hardware and software maintenance costs, consultant costs, marketing monitoring costs and training and travel costs. The table below provides information on the 2019 Budgets for U.S. ISOs/RTOs.

Table 4: Annual Budgets for Existing ISO/RTOs (2019)

ISO/RTO	2019 Budget ($000,000s)	Employees
CAISO[80]	$193.5 ($0.807/MWh)	643
ERCOT[81]	$228.01 ($0.555/MWh)	749
SPP[82]	$193.8	~605
MISO[83]	$339.8	~900
PJM[84]	$363.08	~920
NYISO[85]	$168.2 ($1.071$/MWh)	~570
ISO-E[86]	$196.90 ($1.310/MWh)	~584

Other ongoing costs include consumer outreach and education, software and other information technology upgrades, and monitoring and oversight costs. For example, Texas had a budget of $24 million to educate customers during the first two years after retail competition was implemented.[87] In addition to customer education, Texas hired additional customer service representatives to address increased complaints and bill resolutions pertaining to issues with implementing a restructured market.[88]

80 CAISO Briefing on Draft FY2019 Revenue Requirement, November 13, 2018.
81 ERCOT's 2018/2019 Biennial Budget Submission.
82 SPP 2019 Budget Preliminary Draft, Prepared by Accounting Department, 10/8/2018.
83 2019 Budget, Board of Director Meeting, December 6, 2018. Budget of $339.8 includes both operating and capital budgets.
84 Finance Committee Letter to the PJM Board, September 21, 2018.
85 NYISO 2019 Budget Overview, October 31, 2018.
86 ISO New England Proposed 2019 Operating and Capital Budgets, August 10, 2018
87 PUCN, Energy Choice Initiative Final Draft Report, Docket No. 17-10001, April 2018, pages 62-63.
88 This increase in customer complaints in Texas is discussed in Chapter VII, below.

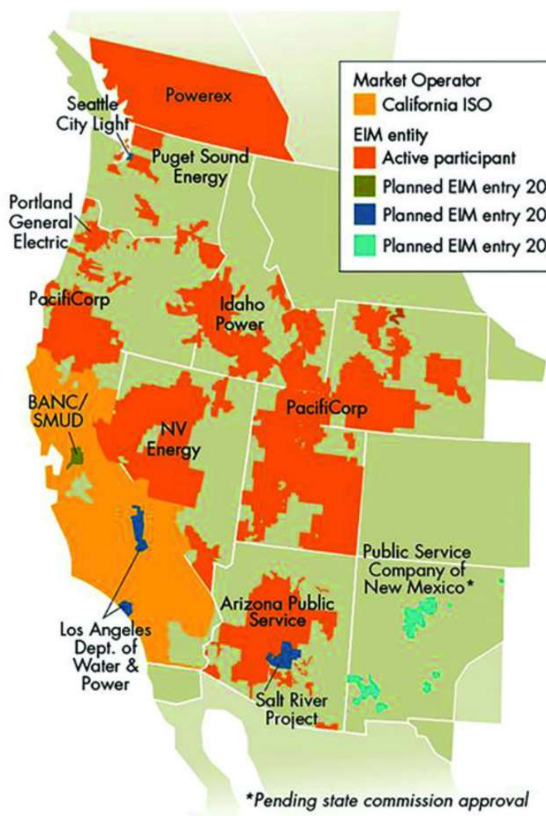
In addition, for those regions with competitive retail markets, there is a cost of administration of billing data which is needed for competitive retail providers to bill customers. The exchange of this billing data between the ISO/RTO and the competitive retail provider requires software solutions, communication protocols and is time and resource intensive, resulting in additional administrative costs.

F. Arizona Specifics

APS currently participates in the Western EIM operated by the CAISO. The EIM is a real-time only energy market that dispatches low-cost energy to serve real-time consumer demand across a wide geographic area. The CAISO began operation of the Western EIM on November 1, 2014, making its markets available to entities outside of its ISO territory. The EIM facilitates renewable resource integration and increases reliability by sharing information on electricity delivery conditions between balancing authorities across the EIM region. It allows participants to buy and sell power close to the time electricity is consumed and gives system operators real-time visibility across neighboring grids. The market platform balances supply and demand fluctuations by automatically identifying lower-cost resources from across a larger region to meet real-time power needs.

Initially, Western EIM resources were only being optimized across the CAISO and PacifiCorp balancing authority areas. But since that time, NV Energy, APS, Puget Sound Energy, Portland General Electric, Idaho Power, and Powerex have become participants in the EIM. The footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming, even extending to the Canadian border, as shown in Figure 9 below.

Figure 9: Western EIM



Recently, TEP announced that it had signed an agreement with CAISO committing to joining the EIM in April 2022. TEP's announcement came just two weeks after Avista announced it would be joining up with the EIM at the same time, potentially bringing the market's participation level to 15 out of 37 balancing authorities in the West. With APS already trading in the market, and SRP slated to join in April 2021, TEP's membership will expand the EIM's reach to include all of Arizona's major population centers.

While participation in the EIM provides some cost benefit to Arizona consumers in leveraging the benefits of a real-time energy exchange, it does not offer all of the products, services, benefits, and efficiencies of a fully functioning wholesale market. The benefits of real-time energy exchange are only a fraction of the total benefits that an ISO/RTO provides by leveraging all of the physical products and financial tools to ensure that the wholesale market is providing least cost energy to the market.

In response to the anticipated introduction of retail competition in the mid-1990s, the Az ISA was formed in September 1998 as a non-profit Arizona corporation to support the provision of comparable, non-discriminatory retail access to the Arizona transmission system. The ISA was intended to be a predecessor to the Desert Southwest Transmission and Reliability Operator ("Desert STAR"), a multi-state RTO with responsibility for security coordination, scheduling, and congestion management, and with its pricing designed to eliminate pancaked transmission rates. Efforts to implement Desert STAR were eventually abandoned.

There is little resemblance between Az ISA and an ISO/RTO. Federal regulatory changes in the two decades since the Az ISA was originally developed and approved by FERC would require significant updated protocols to include such FERC requirements as annual and monthly allocation auctions and the trading of transmission rights. As an indication of this difference, the most recent available financial information for AZ Isa shows an annual budget of $132,950 for one employee; this contrasts starkly with the figures for existing ISO/ RTO, as shown above, with many hundreds of employees and annual costs in the hundreds of millions of dollars.[89]

G. Resource Planning

In regulated markets, IOUs are required to develop detailed plans to meet their customer needs for energy over a decades-long time horizon. This ensures that the IOUs have a diverse portfolio of resources, reflective of the state's energy policies, sufficient to reliably serve their customers. In a restructured market, customers can choose their competitive supplier, and can change suppliers on a regular basis. The amount and type of new generation is determined by market forces, and resource planning is largely removed from the jurisdiction of the public utility commission and the state in general. The state generally retains siting and environmental oversight but is constrained regarding other elements of resource planning.

The tension between competitive markets and regulatory authority has been illustrated recently by the efforts of Maryland, New Jersey, and other states to contract for certain generation resources that these states deemed would be advantageous for customers and the system. On April 19, 2016, the US Supreme Court overturned a Maryland Public Service Commission approval of a compensation arrangement for a new in-state power plant, ruling that, in approving the plan/PPAs, the PSC

89 Arizona Independent Scheduling Administrator Association Approved Budget March 31, 2019 of $33,237.50 x 4 = $132,950. http://az-isa.org/az_isa_financial_info.htm

encroached on FERC authority over PJM.[90] Similarly, in New Jersey, the US Supreme Court declined to hear an appeal of a lower court decision that overturned New Jersey's Long-term Capacity Agreement Pilot Program law, which required the NJ Board of Public Utilities to develop a program under which the state's electric utilities would enter into long term contracts for 2,000 MW of generation.[91] In light of the recent and potential retirement of nuclear generation plants, several states have developed programs to ensure the continued operation of such units for clean energy, reliability, and economic purposes. New York[92] and Illinois[93] have ZEC programs, which provide subsidies for nuclear generation, as part of the NY Clean Energy Standard (finalized by the NY PSC in August 2016) and Illinois statute (passed in December 2016). These programs have been challenged in state and federal courts by competitive market proponents.[94]

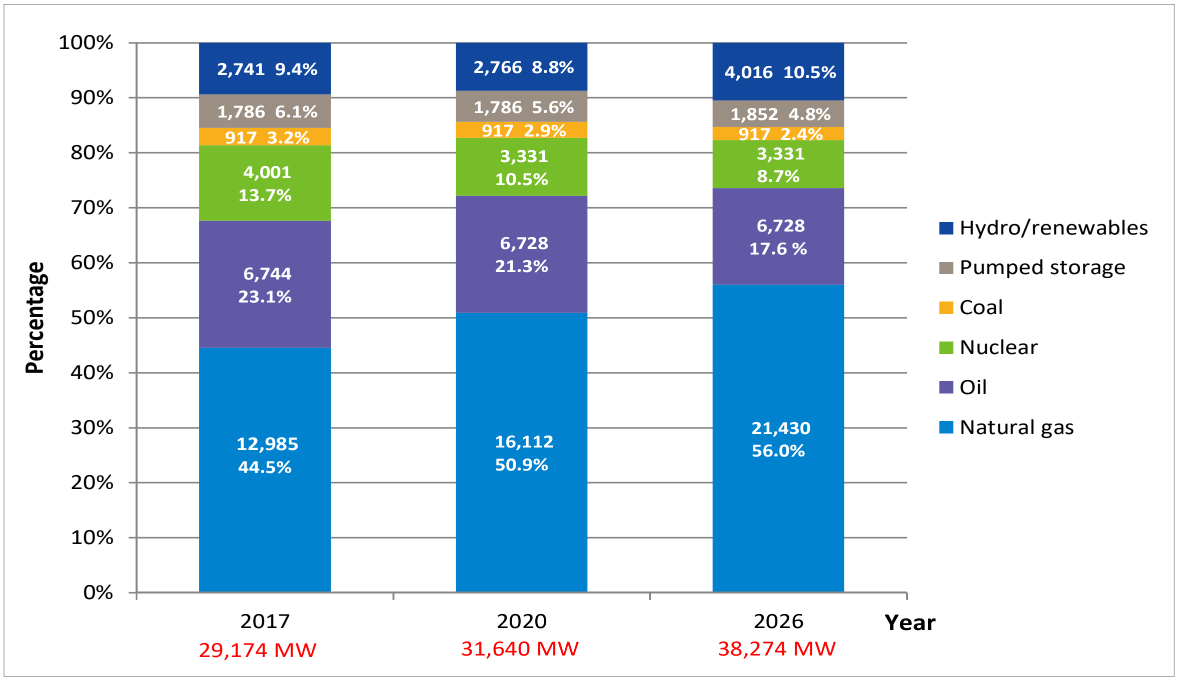
H. Fuel Diversity and Supply

Due to factors such as low natural gas prices, environmental restrictions on coal generation, and other economic factors, restructured states (as well as traditionally regulated states) have seen their reliance on natural gas steadily increase, as more fully discussed in Chapter VIII. In the Mid-Atlantic region, coal and natural gas have reversed roles as fuel sources for electric power. Coal is expected to decline from 42% in 2007 to 27% in 2020, while the share for natural gas is expected to increase from 33% to 43% over this same time period.[95] While grid operators have taken steps to ensure the reliability of the system while accommodating more gas-fired generating capacity, they continue to introduce mechanisms to ensure the resiliency of the grid.

New England has also seen its generation fleet becoming increasingly comprised of natural gas units, which provided over 60% of generation to serve load in 2017 as shown in Figure 10 below.

90 Lillian Federico, S&P Global; "As a follow up to Maryland PPA decision, U.S. Supreme Court declines to review nullification of NJ's LCAPP law" (April 25, 2016).
91 Ibid.
92 "Why Court Victories for New York, Illinois Nuclear Subsidies are a Big Win for Renewables." Julia Pyper, Greentech Media. July 31, 2017.
93 State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois"
94 State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois."
95 The Philadelphia Inquirer, "Growth of gas is no threat to the power grid's reliability, PJM says", published March 30, 2017. Information in article sourced from PJM Interconnection study entitled "PJM's Evolving Resource Mix and System Reliability", dated March 30, 2017.

Figure 10: New England's Summer Capacity by Fuel Type



Source: ISO-NE 2017 Regional System Plan

ISO-NE has outlined the challenges, citing the "fuel-security risks to system reliability." An ISO-NE report discusses the causes of this risk, including: heavy reliance on natural-gas-fired capacity; reliability issues due to limited natural gas transmission infrastructure into the region, as well as limited fuel storage; lack of firm fuel contracts by natural gas generators; retirement of non-gas-fired generation (nuclear, coal, etc.); exposure to winter electricity price spikes; and higher variable cost peaking units (e.g., LNG).[96]

ISO-NE, similar to many restructured regions, does not require generators to have firm fuel supply in the form of either firm gas supply or fuel oil back up. This has resulted in the region experiencing severe fuel shortages at times when system reliability was at risk due to lack of firm fuel supply.

Massachusetts, which is a fully restructured competitive electric market, provides an instructive example of a restructured state struggling with reliance on natural gas in a transmission constrained area. As a potential measure to address this in recent years, the Massachusetts State Energy Office put forth, and the Department of Public Utilities ("DPU") supported, a measure allowing the electric distribution utilities to contract for capacity to support new natural gas pipeline infrastructure, even though the distribution utilities own no generation. This effort was eventually defeated by a Massachusetts Supreme Judicial Court decision, due to a restructuring related statute.

I. System Reliability

Restructured markets have been challenged in their ability to provide the compensation needed by critical resources to meet system reliability needs. New entry – i.e., new generation plants that are coming online - as well as existing generation, have not recovered their fixed and variable operating costs, including fuel, fixed and variable operating and maintenance expenses, and a return on and of

96 Source: ISO-NE 2017 Regional System Plan.

investment due to historically low market prices. In its most recent State of the Market Report, ERCOT's Independent Market Monitor noted that "the ERCOT market continued to provide net revenues well below the level needed to support new investment."[97] The percentage of recovered operating costs for new gas-fired resources is shown in Table 5.

Table 5: Percentage of Recovered Costs for New Resources - 2016[98]

	ISO-NE	NYISO	PJM	Midwest ISO
Combined Cycle	45%	53%	92%	44%
Simple Cycle	66%	92%	79%	38%

The inability of generating resources to recover their operating costs has the potential to threaten the reliability of supply. Texas provides a recent example of this challenge. Reserve margins in Texas have decreased since the introduction of restructuring in the state. Reserve margins serve as a measure of the generating capacity that is available to meet customer demand. Sustained low reserve margins can have significant consequences including blackouts, system reliability incidents and operator interventions.

Prior to deregulation, the reserve margin in Texas was one of the highest in the country.[99] NERC reported that ERCOT had a reserve margin ratio in 2011 of about 14%, nearly a 40% decline from pre-restructuring level and far below the national average at that time of around 25%.[100] In 2012, the PUCT voted to raise the wholesale price cap from \$4,500/MWh to \$9,000/MWh over the next few years.[101] As described in a Texas newspaper: "The move is aimed at ensuring that Texans will have enough power in the future because, as the theory goes, higher prices give power companies more incentive to build new power plants. Texas officials say that the state needs more power plants in the coming years to avoid blackouts while meeting the needs of the growing population and economy."[102]

The reserve margin in Texas continues to decrease despite the increase in price caps, which are designed to provide generators the opportunity to recover not only their fixed costs, but a profit beyond their fixed costs and incent new entry into the region. As shown in the figure below, price caps have been steadily increasing since 2010.

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97 2018 ERCOT State of the Market Report, June 2019, page 112.

98 Values are from the 2016 State of the Market Reports and are approximate. The values reflect an unconstrained zone (NY West/ISO-NE West/Michigan/Dominion (PJM).

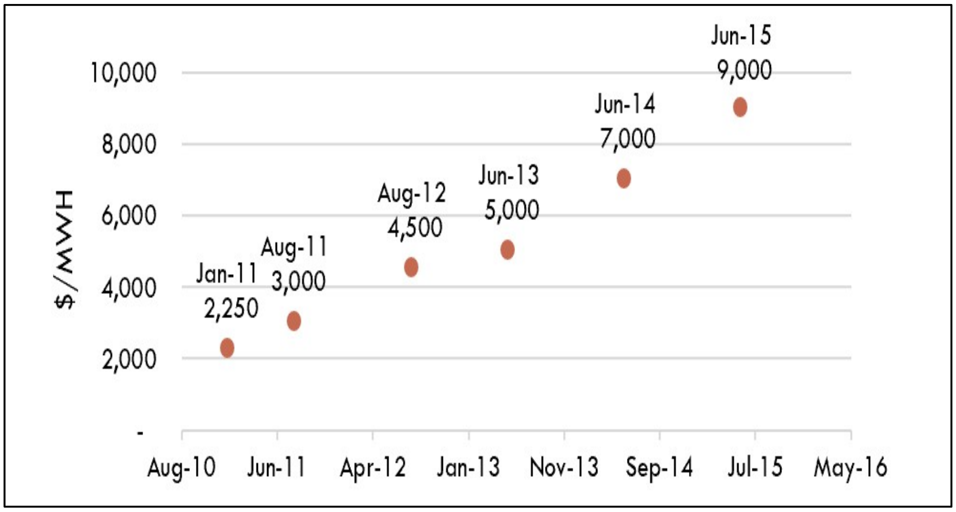
99 Deregulated Electricity in Texas, Texas Coalition for Affordable Power, March 2014, page 62.

100 Deregulated Electricity in Texas, Texas Coalition for Affordable Power, 2017 Edition, page 63.

101 Bade, G., "Texas regulators direct higher plant payments amid capacity crunch concerns," Jan. 22, 2019. (https://www.utilitydive.com/news/texas-regulators-direct-higher-plant-payments-amid-capacity-crunch-concerns-1/546540/)

102 Galbraith, K., "Regulators Double Cap for Electricity Prices," Oct. 25, 2012, https://www.texastribune.org/2012/10/25/texas-regulators-act-texas-electricity-prices/.

Figure 11: ERCOT Wholesale Market Price Offer Caps[103]



However, despite the increases in the officer caps, ERCOT projects reserve margins in the summer of 2019 of 7.4% as compared to ERCOT's target reserve margin of 13.75%[104]. See Figure 12**:** below. In response, the PUCT "directed ERCOT to tweak its operating reserve demand curve (ORDC), which provides a price adder during periods of generation scarcity, and to proceed with implementing real-time co-optimization."[105] ERCOT's Seasonal Assessment of Resource Adequacy ("SARA") report for summer 2019 notes: **"**In all of the scenarios studied for the final summer SARA, ERCOT identified a potential need to enter Energy Emergency Alert (EEA) status in order to maintain system reliability.**"**

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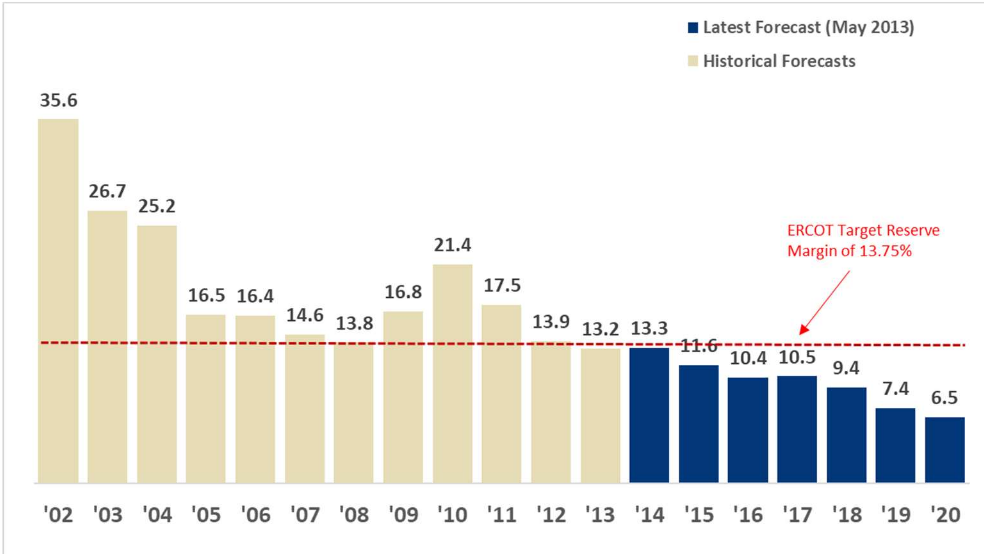
103 FERC Technical Conference Presentation, "Scarcity Pricing in ERCOT," June 27-29, 2016, page 4, https://www.ferc.gov/CalendarFiles/20160629114652-3%20-%20FERC2016_Scarcity%20Pricing_ERCOT_Resmi%20Surendran.pdf.

104 ERCOT, "High demand and tight reserves may result in energy alerts this summer," March 5, 2019, http://www.ercot.com/news/releases/show/176704. (Note: as of December 2018, ERCOT had forecasted a reserve margin of 8.1% but this fell after the loss of Gibbons Creek. See: ERCOT Capacity, Demand and Reserves Report, December 2018.)

105 "Texas PUC Responds to Shrinking Reserve Margin," Tom Kleckner, January 18, 2019. (https://rtoinsider.com/ercot-puct-reserve-margin-109500/).

Figure 12: ERCOT Summer Reserve Margin 2002-2020[106]



In the most recent planning reserve margin forecast released in May of 2019, ERCOT highlighted that the summer reserve margin will rise to 15% by 2021 but then fall back to 7.8% in 2024, far below the 13.75% target reserve margin.

Chairman DeAnn T. Walker of the PUCT has expressed concern: "I am greatly concerned with the results shown in ERCOT's most recent report on capacity, demand, and reserve ("CDR") that was issued on Tuesday, December 4, 2018. In addition, there has been the announcement of the retirement of the Gibbons Creek plant that brings the reserve margin even lower. I truly believe that the Commission must take some action to address the sinking reserve margins in ERCOT…"[107] Chairman Walker went on to call the 7.4% projected reserve margin "very scary".[108]

California provides another example. In June of 2000, a series of localized, rolling blackouts affected 97,000 Pacific Gas & Electric consumers in the Bay Area.[109] The grid operator ordered the cuts because supplies were low due to the closure of several plants for maintenance purposes. The rolling blackouts were declared in hopes of avoiding a major statewide, uncontrolled blackout. Since that time, California has instituted rolling blackouts on several occasions.

J. Price Volatility

Electricity prices area highly-volatile. Moreover, because wholesale electricity markets are an unusual combination of market-driven participants and regulated utilities, they harbor higher risk than other commodity markets. This can be seen in the recent history of spot prices of various energy commodities in the U.S.

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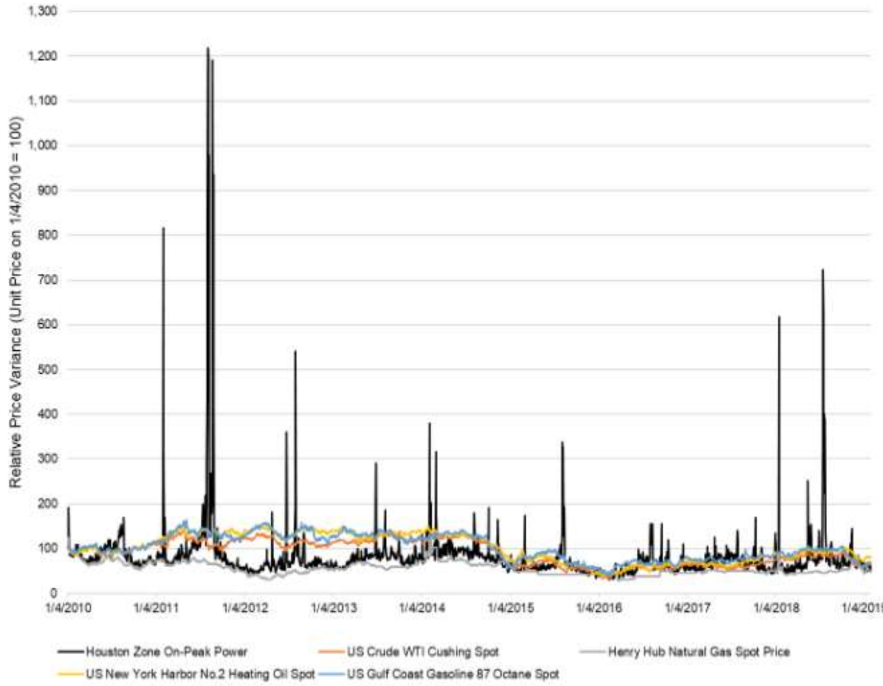
[106] Association of Electric Companies of Texas, Inc. Update on the Texas Electric Industry, January 23, 2014, http://www.aect.net/legislative-staff-briefing-update-on-the-texas-electric-industry-2/.

[107] Memo from Chairman DeAnn T. Walker to Commissioners Arthur C. D'Andrea and Shelly Botkin, January 16, 2019, http://interchange.puc.texas.gov/Documents/48539_33_1004833.PDF.

[108] Bade, G., "Texas regulators direct higher plant payments amid capacity crunch concerns," Jan. 22, 2019, https://www.utilitydive.com/news/texas-regulators-direct-higher-plant-payments-amid-capacity-crunch-concerns-1/546540/.

[109] Frontline, The California Crisis, https://www.pbs.org/wgbh/pages/frontline/shows/blackout/california/timeline.html

Figure 13: Spot Prices for Power and Fuels (2010-2019)[110]



This price volatility can have real implications for customers. The risk associated with the volatility is priced into the energy and fuel contracts that are executed to serve customers, resulting in higher customer costs. This is illustrated in the most recent report of the Independent Market Monitor for the PUCT, which reported that in 2018 as compared to 2017, the average price for natural gas increased by 8% and the average real-time electric energy price increased by 26.%.[111]

[110] Florida Chamber of Commerce.

[111] Potomac Economic, "2018 State of The Market Report for The ERCOT Electricity Markets" (June 2019) Page i.

VII. Retail Market Considerations

A. Impact of Restructuring on Retail Electric Rates

Views regarding the benefits or potential harm of retail competition on different groups, or "classes", of customers vary. These experiences are reported below.

1. Residential Customers

It is challenging to compare retail electricity prices across states due to substantive differences in the structure, regulation, and economic conditions affecting the power industry.[112] For example, a state's electricity rates reflect infrastructure, fuel prices, weather, regulatory costs, tax policy, and other factors that vary state-to-state. In restructured states, these prices may also reflect state-specific rate caps or other mechanisms that are designed to protect customers during the transition to competition on at least a temporary (sometimes years) basis. Further, retail electricity rates used in comparisons typically include many other components (e.g., transmission and distribution costs) in addition to the cost of generation. This does not eliminate the instructive value of an examination of other states' electricity rates and experiences with restructuring. It does, however, suggest that this examination be considered in a broader context and be used directionally or anecdotally rather than as an absolute.

In general, available evidence does not support the assertion that retail competition will necessarily reduce rates for residential customers. While some studies conclude positive or negative price impacts, other academic and industry research finds that there is no conclusive link between pricing advantages for retail customers and electric industry restructuring. The conclusions from the Guinn analysis are echoed consistently throughout the research: "This report has found that some people in restructured states have enjoyed the benefits of retail electric competition, while others have confronted unfavorable outcomes. The impact of restructuring turns largely on market design and policy decisions rendered before and during the implementation phase. But even those states that proceeded with caution and careful consideration were not invulnerable to unintended consequences."

Data provided by the Energy Information Administration ("EIA") and shown in the figures below are often used in academic literature to quantify the effects of restructuring. Some recent studies have backed away from EIA data because it "provides an incomplete assessment of total bills that residential, industrial and commercial customers receive".[113] Nevertheless, the figures below, based on EIA data are illustrative in that they show directionally how average electric prices have changed over time.

Figure 14 and Figure 15, below, use EIA data to compare prices in restructured and non-restructured states. These figures suggest that restructured states have significantly higher rates than traditionally

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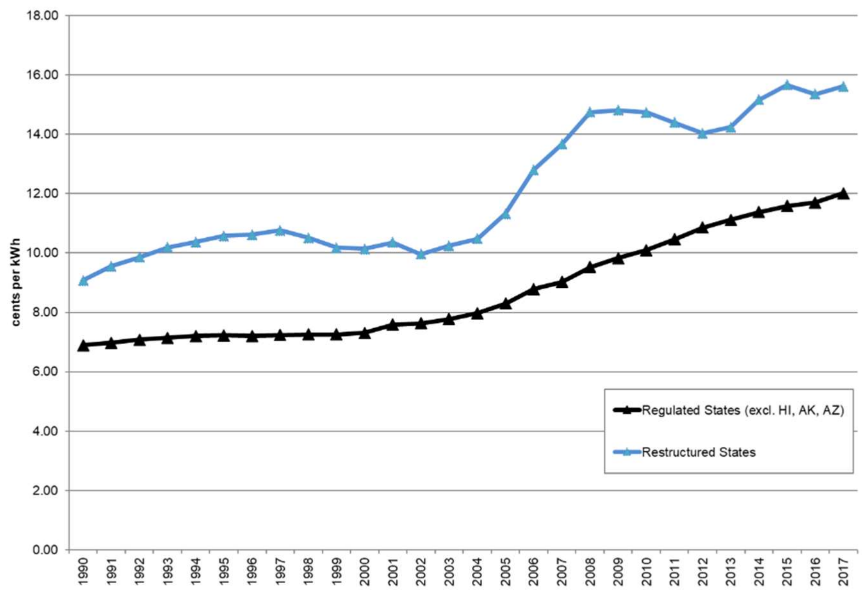
112 This limitation in state-to-state comparisons is noted in many academic studies of the effects of restructuring. See, for example, Severin Borenstein and James Bushnell, "The U.S. Electricity Industry after 20 Years of Restructuring." (Revised May 2015).

113 Dormady, N., Hoyt, M. Roa-Henriquez, A. & Welch, W. 2019. Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, at 4. See also: Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, page 28.

regulated states. According to the data, from 1990 to 2017, rates in restructured markets have been on average 42% higher than rates in regulated markets.[114]

Figure 14: Average Residential Rate of Restructured and Regulated States (Before and After Restructuring)



Data source: EIA Electric Power Monthly, October 12, 2018.[115]

Figure 14 above provides context relative to a recent analysis by a retail competition advocacy organization that compares changes in electric rate trends in states with and without retail competition, entitled "The Great Divergence in Competitive and Monopoly Electricity Price Trends."[116] Consistent with Figure 14 this analysis recognizes that electric rates are higher in restructured vs. non-restructured states, and attempts to track the magnitude of this difference between states with and without retail competition between 2008 and 2017.[117] This study seeks to convey that the price difference between restructured states and non-restructured states has decreased since 2008. Using 2008 as the initial year in this comparison conveys an inaccurate picture of the impact of restructuring and gives an inaccurate representation of the change in the difference in electric rates between states with and without retail competition.

Figure 14 shows the difference in residential rates between retail competition and non-retail competition states peaked in and around 2008. As discussed in Chapter IX, below, this phenomenon was largely driven by the increase in natural gas prices up through 2008 which impacted restructured markets more than non-restructured markets. Because this difference peaked in 2008, showing that the difference decreased starting at that time, i.e., as natural gas prices decreased, does

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[114] Regulated markets exclude Alaska and Hawaii, given the impact of their unique geographic characteristics on higher electric prices at nearly double or more than double the U.S. average, respectively. See: https://www.eia.gov/state/print.php?sid=AK; http://energy.hawaii.gov/wp-content/uploads/2018/06/HSEO_2018_EnergyFactsFigures.pdf.

[115] Restructured states include: CT, DC, DE, IL, MA, MD, ME, NH, NJ, NY, OH, PA, RI, and TX.

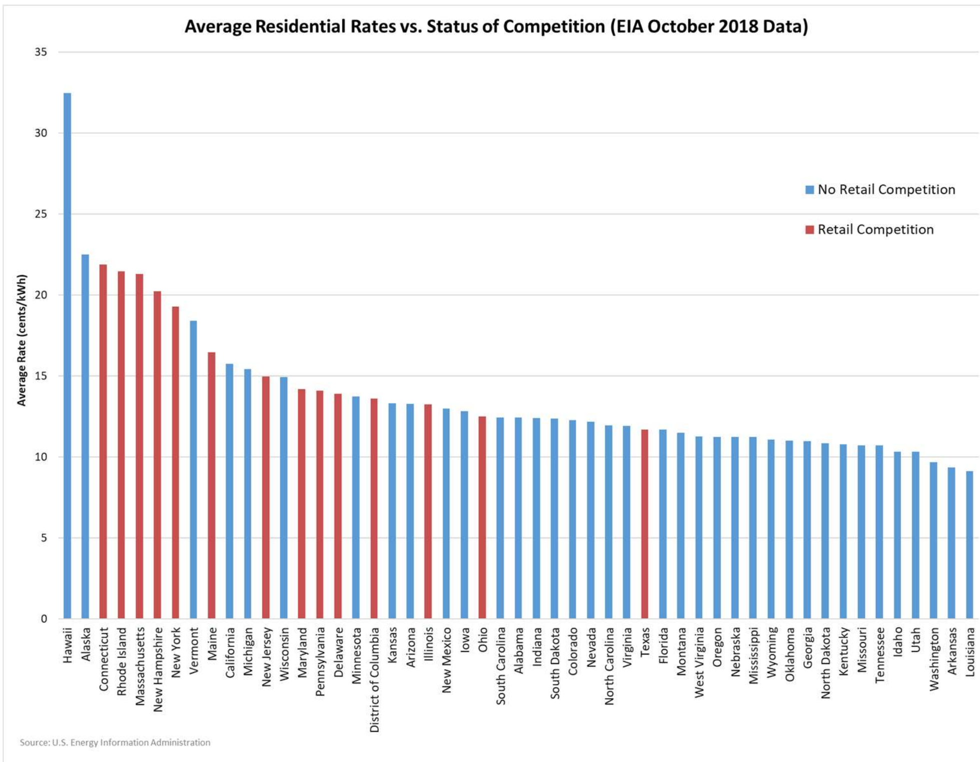
[116] See, O'Connor, Phillip R., Ph.D. and Khan, Muhammad Asad, "The Great Divergence in Competitive and Monopoly Electricity Price Trends," Retail Energy Supply Association, September 2018.

[117] O'Connor and Khan, page 5.

not reflect an accurate picture of the impact relative to restructuring, which was generally implemented long before 2008.

The chart below provides a representation of the difference in average residential rates between restructured and regulated states. Aside from Hawaii and Alaska, which are outliers in terms of having average residential rates that are approximately double the country's average, the most expensive rates in the U.S. are predominantly in states that have retail competition.

Figure 15: Average Residential Rates



Source: EIA, Electric Power Monthly, October 2018

Texas provides an instructive example of a fully restructured market. In January 2002, Texas Senate Bill 7 ("SB 7") restructured a portion of Texas' electric market.[118] Municipal and cooperative utilities were permitted to opt out, but IOUs were required to split into three separate companies: generation, transmission and retail (specifically customer service and billing). The Texas Coalition for Affordable Power ("TCAP") produces annual analyses that assess the competitive market and the impact on retail prices. In its 2014 study, TCAP found that restructuring had cost Texas customers $22 billion from 2002 – 2012.[119] This annual trend began during the very first year of the retail electric deregulation[120] in Texas and has continued through 2017, as shown in Figure 16.

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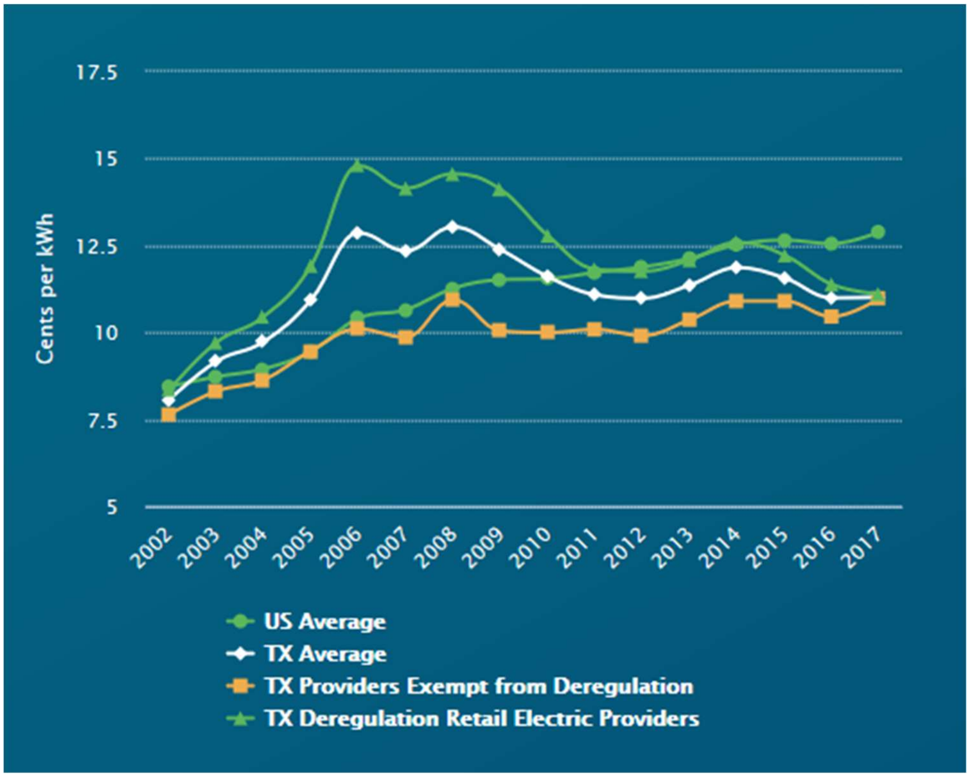
118 Texas restructured its ERCOT region only. For more information, see: http://www.ercot.com/content/wcm/lists/172484/ERCOT_Quick_Facts_02.4.19.pdf

119 TCAP 2014 Electric Restructuring Report, page P5.

120 deregulation is another term that has the same meaning as restructuring.

Figure 16: Average Residential Electricity Prices in Texas[121]



In its most recent 2019 report, TCAP concluded that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation.

2. Transitional Price Caps

Several states imposed regulatory price caps on incumbent utilities' supply rates following restructuring. This was done to protect customers from rapidly increasing market prices during the transition to a restructured market. In some circumstances, these price caps helped create short-run benefits by establishing the "price to beat" for merchant power providers, who then "beat" those prices for a period as the market developed. However, as these artificial price caps began to expire, the average price of electricity increased. When Illinois retail price freezes expired in 2007 "bills soared up to 55% for Ameren customers and 26% for those of Commonwealth Edison."[122] Maryland froze prices to customers who continued to rely on utility sales service at levels that were approximately 5% below pre-restructuring levels only to have them increase by over 70% as soon as the caps were removed.[123]

In an effort to encourage the presence of alternative suppliers in Texas, the incumbent providers in that state charged a "price to beat," which remained in effect until the alternative suppliers made up a sufficient portion of the market. The price acted as a price floor, preventing incumbent providers

[121] https://tcaptx.com/reports/snapshot-report-electricity-prices-texas-may-2019

[122] Davidson, Paul. "Shocking Electricity Prices Follow Deregulation." ABC News and USA Today, August 12, 2007. Article accessed January 30, 2019.

[123] Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, page 41.

from charging artificially low rates to hinder competition. The price to beat included a 6% discount off the utility's base rates, as adjusted for fuel costs.

3. Larger Commercial and Industrial Customers

As described above, a clear picture has not emerged on whether or not residential customers in restructured states benefit from lower prices as compared to those in regulated states. Research does suggest that larger customers (commercial and industrial) are more likely to experience price benefits than smaller customers in restructured states.

A study by Dormady *et al* ("Dormady Study") examined bill data in Ohio to estimate cost impacts, in particular the varying impacts on customers in different customer classes (e.g., large C&I customers). This study concluded that:

> *…retail restructuring has reduced or had no effect on price disparities between customer classes, with several notable exceptions. First, the findings suggest that, where customers observed savings associated with retail choice, the greatest savings have been observed by industrial customers and, where customers have observed cost increases, the greatest increases have been observed by residential customers.* [124]

Research does not consistently show consistent or sustained rate reductions to large commercial and industry customers. One study showed that the difference in prices paid by industrial customers in restructured market states nearly tripled from 1999 to July 2007 compared to similar customers in regulated states. An important factor regarding this difference is that restructured states were more subject to changes in natural gas prices, which were increasing during this period, than traditionally regulated states. While this example is dated, it relays the experience in markets shortly after restructuring.[125]

4. State Evaluations of Restructuring Impacts on Retail Rates

Some states have recently completed evaluations of whether residential and small commercial customers are better or worse off by switching to retail providers. For example, the Massachusetts Attorney General ("AG") delivered a paper in March 2018 to determine "whether residential consumers in Massachusetts pay more or less for their electric supply when they buy it from the competitive marketplace rather than their electric company."[126] The final analysis showed that Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017. A third year of data shows residential customers lost another $76.2 million, for a three-year total of $253 million."[127] The Massachusetts AG's recommendation

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[124] Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, Dormady, Hoyt, Roa-Henriquez, Welch, December 2018, at 2. The Dormady Study also notes that while some savings may accrue on the energy commodity portion of the bill, that this could be more than offset by increases in other components of the bill, in particular cost recovery mechanisms associated with divested power plants to affiliates: "the findings suggest that, while customers have generally observed some savings associated with the implementation of competition (i.e., the deregulated component of their bill), savings have generally been more than offset by cross subsidies to arms-length deregulated generation affiliates ("gencos") (Type II cross-subsidization)."

[125] Competitively Priced Electricity Costs More, Studies Show, David Cay Johnston, The New York Times, November 6, 2007

[126] Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, page viii.

[127] Tepper, Rebecca, Chief of Energy and Telecommunications Division, Massachusetts Attorney General's Office, Presentation to the New England Restructuring Roundtable, "Suppliers Are Not Providing Value to Individual, Residential Customers," October 12, 2018, slide 4.

was to eliminate the electric supply market for individual residential customers because the cost of retail supply was higher by far than the basic service provided by the utilities.

In New York, the NY PSC ordered competitive electric suppliers to cease signing up new customers due to customers paying more for electricity provided by competitive suppliers than what they would have paid based on utility rates. The NY PSC order demonstrates the frustration the commission had in overseeing the competitive retail market for the public's benefit. In particular, the NY PSC wrote:

> *"experience shows that, with regard to mass market customers, [energy service companies or "ESCOs"] cannot effectively compete with commodity prices offered by utilities. This may be for a number of reasons, including customer acquisition costs, the greater economies of scale of utilities, and the fact that utilities do not profit from the sale of energy commodity. In addition, the Department of Public Service continues to receive a large number of complaints from ESCO customers about unexpectedly high bills."*[128]

Other states have reached similar conclusions after similar reviews. A Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million more than the default service costs.[129] In Connecticut a study completed by the Office of the Consumer Counsel concluded that in 2015, customers who switched to a competitive supplier paid almost $58 million more than they would have if they had remained with their default supplier.[130] A 30-month study conducted by the NY PSC found that customers who switched electric and gas suppliers paid nearly $820 million more than if they had remained with their default suppliers.[131] Illinois AG Lisa Madigan reported that residential and small commercial customers enrolled with competitive suppliers paid over $600 million more for electricity in the last four years than if they continued to purchase their electricity from the regulated utility.[132]

B. Customer Participation in Retail Competition

1. Residential Customers

A recent U.S. EIA report shows that residential retail competition participation has declined since its peak in 2014 and includes Figure 17 below.[133]

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128 New York Public Service Commission Order Resetting Retail Energy Markets and Establishing Further Process, CASE 15-M-0127, (2/23/2016), p. 2. This Order was challenged in the New York court system, and subsequent process is ongoing.

129 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, page 9.

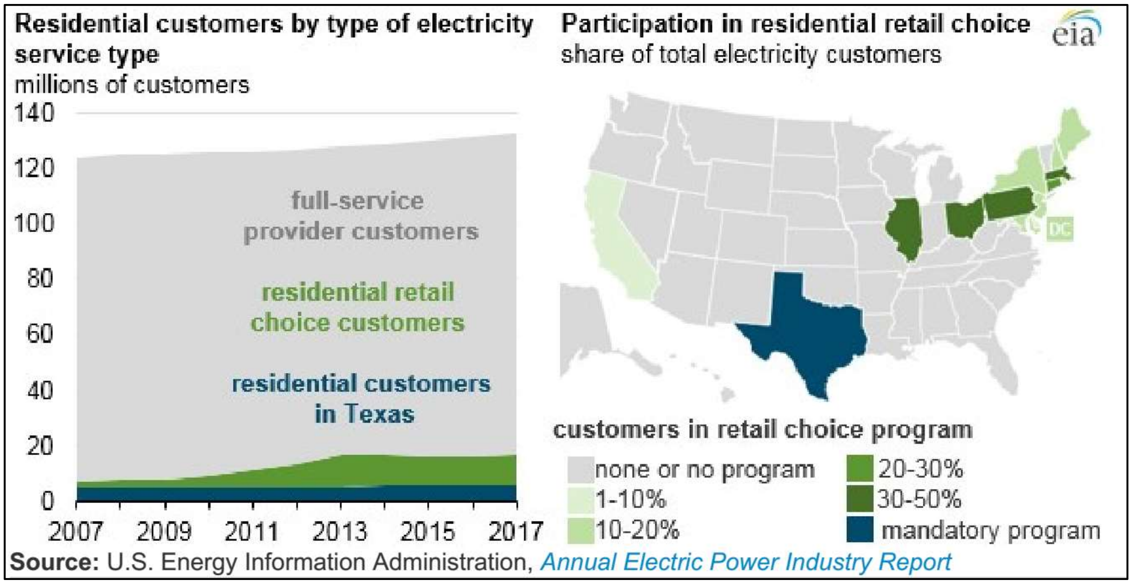
130 Gregory B. Hladky, Study: Consumers Pay Extra for Retail Electricity. Hartford Courant. April 20, 2016. http://www.courant.com/news/connecticut/hc-retail-electricity-costs-above-state-standard-20160420-story.html.

131 Jeff Platsky, AT RISK: NY Reviews Electric, Gas Free-Choice Program; Consumers Ended Up Paying More. Press Connects. February 9, 2018. https://www.pressconnects.com/story/news/2018/02/09/risk-ny-groundbreaking-program-allowing-customers-select-electric-gas-suppliers/302146002/

132 "[Attorney General] Madigan Sues Another Alternative Retail Electric Supplier & Reaches $3 Million Settlement for Defrauded Customers" Press Release, November 19, 2018. http://illinoisattorneygeneral.gov/pressroom/2018_11/20181119b.html

133 US EIA, "Today in Energy: Electricity residential retail choice participation has declined since 2014 peak." (Nov. 8, 2018).

Figure 17: Residential Participation in Retail Competition in U.S.



In cases where customers in restructured states do not select a retail marketer, they are provided default or POLR service, which in many cases is provided by the utility. POLR services act as a backstop to ensure customers that have selected an ESCO will continue to receive electricity even if their supplier leaves the market or fails to meet their contractual purchase obligations within the wholesale market (i.e., default). It should also be noted that some states require POLR services to be selected competitively through a utility RFP.

It is observed that residential customers exhibit "stickiness," meaning that when they are presented with retail competition, many customers either do not switch providers and take service from the POLR, or, in the case of Texas, their initial, incumbent competitive supplier.[134] A recent study of the Texas residential market following restructuring refers to this as "inertia," and describes the prevalence of customers staying with a more expensive provider due to "frictions" (i.e., factors that would impede switching to lower cost providers) including "inattention" - whereby customers don't effectively seek to acquire the information necessary to switch to a better options - and "brand advantage" that consumers afford an incumbent.[135]

2. Community Choice Aggregation

Community Choice Aggregation ("CCA") or Municipal Aggregation refers to the ability of local governments (as authorized by statute) to enter into contracts whereby customers participate in competitive retail supply arrangements, unless they individually opt-out. Interest in this topic in Arizona is reflected in a recent letter issued by ACC Chairman, Robert Burns, which announced a workshop process to address issues related to CCAs during the summer of 2019.[136]

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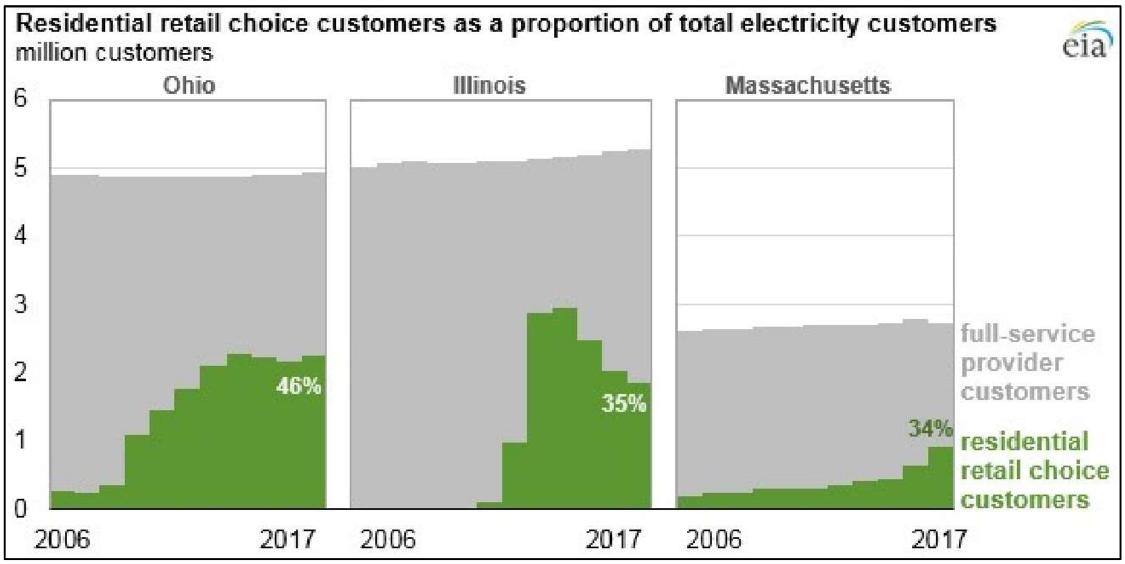
[134] *See, e.g.*: Hortaçsu, Ali; Madanizadeh, Seyed Ali; and Puller, Steven L., "Power to Choose? An Analysis of Consumer Inertia in the Residential Electricity Market," American Economic Journal: Economic Policy 2017, 9(4): 192–226; Sixel, L.M., "It Pays to Switch Power Plans, but Few Houstonians Do," Houston Chronicle July 3, 2018, Updated: July 13, 2018.

[135] Hortaçsu, Madanizadeh, and Puller, pages 192-193.

[136] Retail Electric Competition Docket No. RE-00000A- 18-0405. May 3, 2019.

The use of CCAs has driven increases in residential participation in states like Massachusetts, Illinois, and Ohio. For example, in 2014 in Massachusetts, which implemented restructuring in 1999, approximately 18% of residential customer load was served by competitive supply. This number has grown in the last four years to approximately 47% of residential customer load in 2018, due largely to numerous new CCAs.[137] Illinois saw an increase in residential customer participation in competitive retail electric service as CCAs were introduced in that state from 2009-2013. However, residential customers in Illinois switched back to their default providers at a rate of 16% in 2015 and 18% in 2016. As of 2017, competitive retail providers serviced 35% of total residential customers in Illinois, down from the peak of 57% in 2014.[138] Figure 18 below shows the recent increase in Massachusetts, as well as the recent decline in Illinois.

Figure 18: Change in Residential Customers Participating in Competitive Retail Electric Supply in Three States



There is a variety of perspectives regarding CCAs across restructured states. In some states, the growth of CCAs does not evoke broad concern, and CCAs may be viewed as providing competitive supply options to residential customers in a way that helps to protect customers from potentially negative outcomes related to marketing to individual residential customers.

A recent U.S. DOE Study identified a lack of customer awareness as an additional challenge represented by CCAs. Reflecting that CCAs are a new and relatively unknown concept, the study reported that, according to its research response, "most CCA customers are unaware that any change has occurred in their electricity service."[139] While many CCAs have implemented informational campaigns to increase customer awareness,[140] this may represent an important policy consideration

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137 Electric Customer Migration Data, Mass.gov. Data from 2014 Monthly Electric Customer Migration Data and 2018 Monthly Electric Customer Migration Data – annual data for "Rate Class Load (in %) CG kWh" for "R" (residential) customers. https://www.mass.gov/service-details/electric-customer-migration-data.

138 US EIA, "Today in Energy: Electricity residential retail choice participation has declined since 2014 peak." (Nov. 8, 2018).

139 O'Shaughnessy, Eric, Jenny Heeter, Julien Gattaciecca, Jenny Sauer, Kelly Trumbull, and Emily Chen. "Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets." Golden, CO: National Renewable Energy Laboratory. (February 2019). Page vi.

140 O'Shaughnessy, et al. Page vi.

regarding whether CCAs involve an active customer choice, particularly given the phenomenon of customer "stickiness" described above.

In contrast, in California, the recent emergence of CCAs has led to significant concern, as reflected in the CPUC conducting a multiyear process to proactively identify and address potential negative effects of CCAs and related programs.[141] In particular, California has identified potential threats to core principles of affordability, decarbonization and reliability.[142] CCAs represent a particular challenge in that state due to its industry structure, including the utilities' roles in contracting for generation through long term contracts and supporting resource adequacy, ensuring access and affordability, and financing significant clean energy development and meeting the state's Green House Gas ("GHG") reduction requirements.[143]

In response to this challenge, the CPUC has approved an additional charge for customers in CCAs, the Power Charge Indifference Adjustment ("PCIA"), to ensure that they pay their fair share of approved utility costs associated with clean energy and reliability/ resource adequacy.[144] The PCIA is highly controversial in California, with advocates of CCA's arguing that it is too high and will harm the viability of CCAs, and utilities asserting that it is too low, and will harm customers who remain on the utility's basic service. [145] For example, Pacific Gas and Electric estimates that the current PCIA methodology results in an approximately $200 million CCA cross-subsidization in its service territory. [146] A recent report by the National Renewable Energy Laboratory ("NREL") notes:

> *This dynamic can generate a positive feedback loop: as more customers move to CCAs, basic service rates have to increase to compensate for the under-estimated cost adjustment factored into the PCIA, thus incentivizing more communities to form CCAs. This feedback loop could pose a challenge to utilities facing load loss to CCAs as well as to utility customers in areas not served by CCAs.* [147]

The CPUC is continuing to address this challenge, including recently increasing the PCIA between 1-5%, depending on the utility, and seeking other potential solutions.[148]

In states like California, CCAs also represent a potential reduction in state public utility commission authority and jurisdiction. In California, CCAs have asserted that, as with municipal utilities, certain elements of utility commission jurisdiction do not extend to "new market actors" such as CCAs.[149]

3. Commercial and Industrial Customers

In contrast to residential customers, the migration to retail suppliers by industrial customers has been much greater. Figure 19 below, illustrates that retail access has been popular with commercial and industrial customers, but less popular with residential customers.

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141 Trabish, Herman K. "California Regulators See Signs of a New Energy Crisis – Can They Prevent It?" Utility Dive May 18, 2018.

142 California Public Utilities Staff, "California Customer Choice – An Evaluation of Regulatory Framework Options for an Evolving Electricity Market," August 2018. Pp. iv, 28.

143 O'Shaughnessy, et al. Pages 30-32.

144 California Public Utilities Commission "Fact Sheet - Power Charge Indifference Adjustment" January 2017. THE PCIA also applies to customers in the Direct Access program, i.e., a capped program that allows a limited amount of large customers to purchase power from electric service providers other than their electric investor-owned utility.

145 O'Shaughnessy, et al. Pages 30-32.

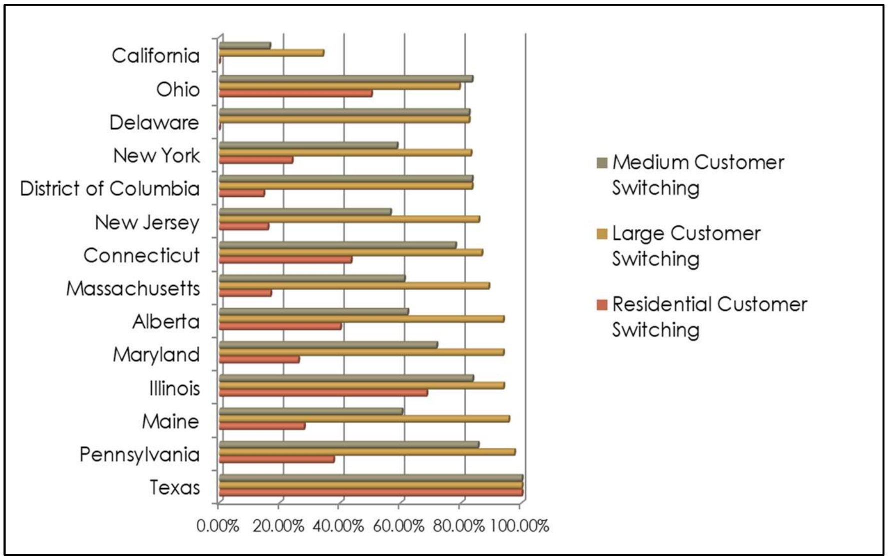
146 O'Shaughnessy, et al. Page 31.

147 O'Shaughnessy, et al. Page 31.

148 O'Shaughnessy, et al. Page 31.

149 O'Shaughnessy, et al. Page 32.

Figure 19: Percent of Customers on Retail Electric Supply by State and Rate Class[150]



4. State Actions

States that have implemented restructuring consistently address consumer protections in either legislation or regulatory orders. A number of states have experienced problems in retail supplier marketing, customer acquisition, billing, and pricing practices. These practices often have an undue impact on low-income, elderly, and non-English speaking customers. Several states have undertaken studies and other actions to address these issues.

The Massachusetts AG developed a study in March 2018 examining the impact of the competitive electric market for residential customers. In explaining the substantially greater costs for customers on competitive supply, the report stated that "Unlike the commercial and industrial market, where sophisticated buyers with demands for large volumes are likely able to negotiate more favorable rates, individual residential consumers are not getting a bargain."[151] Following the publication of this study, the AG issued a press release citing aggressive sales tactics, false promises, higher costs, and the targeting of low-income, elderly, and minority residents, and proposed legislation to end electricity competition for individual residential customers.[152]

Following the filing of a lawsuit against a retail provider in Illinois for violations of that state's consumer fraud laws, Illinois' AG Madigan also called for an end to residential competition, due to deceptive marketing practices.[153] This year, Connecticut Consumer Counsel, in collaboration with

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150 "Annual Baseline Assessment of Choice in Canada and the United States" January 2014, pages 14, 26.

151 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, page viii., p. 15.

152 "AG Healey Calls for Shut Down of Individual Residential Competitive Supply Industry to Protect Electric Customers" Press Release, March 29, 2018. https://www.mass.gov/news/ag-healey-calls-for-shut-down-of-individual-residential-competitive-supply-industry-to-protect

153 "[Attorney General] Madigan Sues Another Alternative Retail Electric Supplier & Reaches $3 Million Settlement for Defrauded Customers" Press Release, November 19, 2018. http://illinoisattorneygeneral.gov/pressroom/2018_11/20181119b.html.

AARP, other consumer advocates, and a U.S. senator, called for the end of residential competition that "economically harms consumers" in Connecticut.[154]

In the New York DPS Order described above which limited competitive electric supplier activity, the Commission described the "large number of complaints from ESCO customers about unexpectedly high bills."[155]

The NY DPS reported that it received over 5,000 initial complaints against ESCOs in 2015, with 1,076 "escalated complaints," (i.e., not initially resolved by ESCOs) which fall into the following categories:

30% - "questionable marketing practices"

25% - "dissatisfaction with prices charged – no savings realized"

22% - "slamming – enrollment without authorization."[156]

The NY Commission ordered that ESCOs may only enroll/ renew retail customers based on contracts that: (1) guarantee savings in comparison to what the customer would have paid as a full-service utility customer, or (2) provide at least 30% renewable electricity. Ultimately this order was challenged, and the process is ongoing.

The Massachusetts AG report states that the Attorney General's Office "continues to receive a large number of complaints concerning competitive suppliers," including more than 700 complaints from 2014-2017.[157]

A review by TCAP shows that after restructuring was implemented in Texas, there was a significant jump in customer complaints. As shown below in Figure 20, complaints to the Texas Public Utilities Commission averaged 1,300/year prior to restructuring; after restructuring, complaints rose to as high as 17,250 in a given year.[158]

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154 "Time to End the Third-Party Residential Electric Supply Market" AARP Connecticut. February 2, 2019. https://states.aarp.org/time-to-end-the-third-party-residential-electric-supply-market/

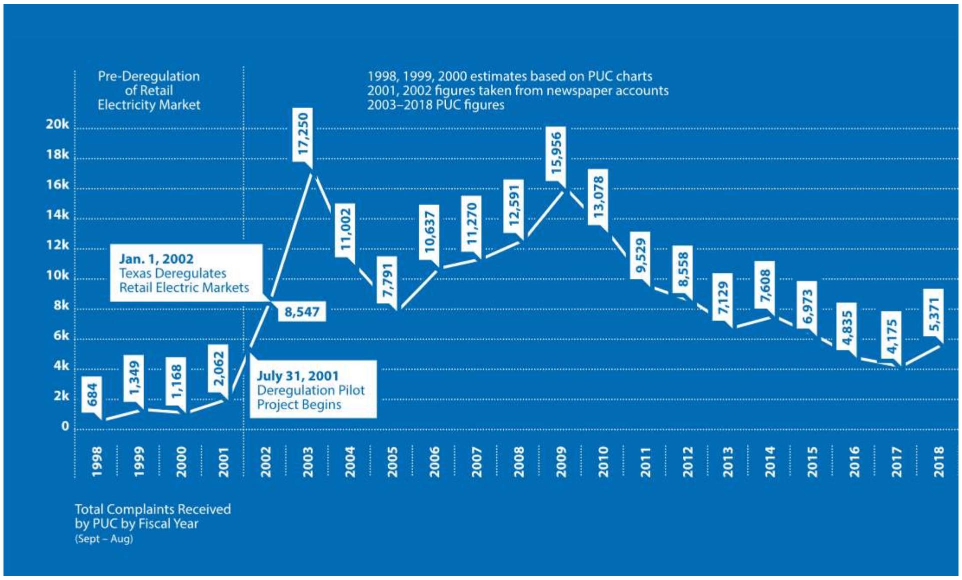
155 New York Public Service Commission Order Resetting Retail Energy Markets and Establishing Further Process, CASE 15-M-0127, (2/23/2016), page 2.

156 *Ibid.*, pages 12-13.

157 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, page 2.

158 TCAP Snapshot report: PUC Complaint Data, 2018 edition.

Figure 20: Annual Electricity-Related Complaints in Texas[159]



5. Actions Against Marketers

There are numerous cases in which state regulators and attorneys general have undertaken punitive action against energy marketers for practices ranging from illegal "bait and switch" schemes, to fraudulent claims about savings, to "slamming" (unauthorized switching of customers to a competitive supplier without proper authorization from customers). Table 6, below, summarizes a selection of such actions.

Table 6: Illustrative Regulator and Attorney General Actions Against Energy Marketers

State/ Province	Illustrative Complaints, Enforcement Actions, Settlements, etc.
Connecticut	The Connecticut Public Utility Regulatory Authority ("PURA") fined Spark Energy twice in 2018. The first fine was for $900,000 in August for showing inaccurate rates on bills. The second fine was for $750,000 in September in response to Spark placing automated calls to customers under the guise of the utility, Eversource.[160] The Connecticut Attorney General and Consumer Counsel petitioned PURA to investigate the marketing practices of Energy Plus, due to customer claims that the company failed to adequately disclose energy rates. Energy Plus paid $4.5 million in a settlement.[161]

159 *Ibid*.
160 Matt Pilon, "Spark Energy Hit with Second Fine", September 11, 2018.
161 Dowling, Brian, "Settlement with NRG Energy Subsidiary Nets State $4.5M For Enforcement," *The Hartford Courant*, May 22, 2014.

State/ Province	Illustrative Complaints, Enforcement Actions, Settlements, etc.
Illinois	In October 2018, Sperian Energy settled a lawsuit with by Attorney General Lisa Madigan regarding deceptive market practices including failing to notify customers of contract lengths and fees. Sperian was required to refund $2.65 million to 60,000 Illinois customers and was banned from marketing to Illinois customers for the following two years.[162] The Illinois Commerce Commission fined Just Energy for deceptive sales and marketing practices and ordered an independent audit of the company's sales program.[163] The Illinois Attorney reached settlement with U.S. Energy Savings Corp. (now Just Energy) that allowed hundreds of customers to terminate contracts and receive $1 million in restitution for misleading sales tactics.[164]
Maryland	The Maryland Public Service Commission ("Maryland PSC") fined North American Power $100,000 for misleading advertisements and ordered the suspension of telemarketing activities in the state.[165] The Maryland PSC fined TES Energy for brokering electric service without a license.[166]
New York	In April 2018, Liberty Power was required to refund $550,000 to New York customers due to deceptive practices including impersonating utility representatives and disguising contracts as billing corrections.[167] In response to a lawsuit filed by New York Attorney General Schneiderman, in 2017 Energy Plus was ordered to reimburse $800,000 to customers. The Attorney General's office concluded that Energy Plus had wrongly promised savings and had misrepresented their cancellation policy.[168] The New York Attorney General reached a settlement with U.S. Energy Savings Corp. (now Just Energy) which required the company to waive hundreds of thousands of dollars in customer termination fees and pay $200,000 to the state.[169]
Ohio	In 2016 the Ohio Public Utilities Commission ("Ohio PUC") fined Just Energy $125,000 for deceptive marketing practices, after customers complained to the PUC that they had received bills from Just Energy without ever signing up for their service.[170]

162 "Attorney General Lisa Madigan: Secures $2.6 Million in Refunds for Illinois Residents Defrauded by Sperian Energy", Press Release, October 21, 2018.
163 Illinois Commerce Commission, "Illinois Commerce Commission Fines Just Energy for Deceptive Sales and Marketing Practices, Orders Audit," Press Release, April 15, 2010.
164 "Madigan Secures $1 Million in Consumer Restitution from Alternative Gas Supplier for Deceptive Claims," Press Release, May 14, 2009.
165 Cho, Hanah, "Electric Choice: Know Your Rights," *Baltimore Sun*, January 7, 2012.
166 "License Briefs," EnergyChoiceMatters.com, April 14, 2011.
167 Bill Heitzel, "Liberty Power Agrees to Fund Customers for Unscrupulous Tactics," April 12, 2018
168 "A.G. Schneiderman Announces $800K Settlement with Energy Service Company That Falsely Advertised Lower Utility Bills", Press Release, August 30, 2017.
169 "Attorney General Cuomo Reaches Agreement with WNY Natural Gas Provider After Consumer Complaints," Press Release, November 10, 2009.
170 Dan Gearino, "Electricity Marketer Just Energy Fined Over Complaints", November 5, 2016.

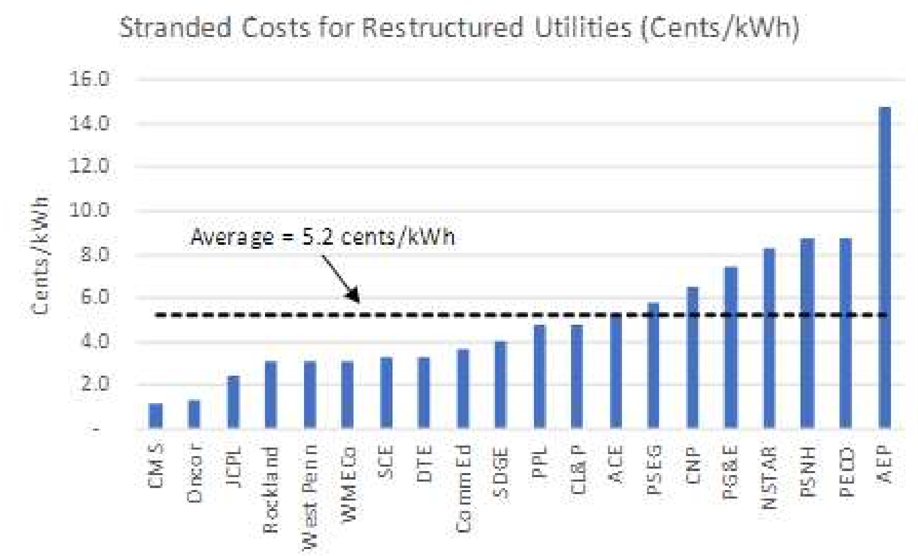
VIII. Generation Divestiture and Stranded Costs

A. Introduction

In many restructured states, IOUs were prohibited from owning generation and were required to divest of their existing generation assets, resulting in stranded costs. Stranded costs are created when the market value of utility assets in a restructured market is less than their value on the utilities' books. Stranded costs are then recovered from customers through their bills.

In states that have restructured – including California, Connecticut, Illinois, Massachusetts, Michigan, New Hampshire, New Jersey, Pennsylvania and Texas – utilities have been authorized to recover over $40 billion in stranded costs from customers, as shown in the figure below.[26]

Figure 21: Stranded Costs for Restructured Utilities (¢/kWh)[171]



Stranded costs are passed directly on to electricity customers generally through non-bypassable wires charges.

The types of stranded costs include:

- Unrecoverable costs of generation assets and infrastructure: If a utility's plant is sold, shut down, or spun off to an unregulated affiliate, its potential stranded costs are measured as the unrecovered capital costs, or "net book value," offset by its market value, salvage value, or administratively determined value. Generation assets include power plants, solar facilities, substations, land associated with future generation sites that no longer can be constructed by the utility, and other associated infrastructure.

[171] To arrive at the ¢/kWh of delivered energy, the total amounts of electric restructuring-related stranded costs, by company, were divided by the five-year average annual kWh sales for that utility beginning with and prior to the initial stranded cost authorization date.

- Uneconomic fuel and other contracts: When a generating plant is sold, shut down, or spun off to an unregulated affiliate, fuel and other contracts associated with the operation of the plant are also transferred. Uneconomic (or "out of the money") PPAs and fuel purchase contracts are contracts that cost more than the utility's incremental cost of producing or procuring the same generation or fuel. This category also refers to renewable contracts that were agreed to in order to comply with state mandated Renewable Portfolio Standards requirements, and can further include transmission contracts, service contracts, and other contracts.
- Regulatory Assets / Liabilities: A regulatory asset is a specific cost that a regulator permits an IOU to defer on its balance sheet because it is probable the cost will be recovered in future periods. Regulatory assets may become stranded under restructuring if they no longer meet the accounting requirements for deferral, and thus would need separate treatment from regulators to ensure recovery. The same is true for regulatory liabilities, which are revenue items that are deferred on the balance sheet.
- Intangibles: Intangibles include things like early retirement and severance packages, job retraining, computer data, and IT systems. Legislators or regulators in California, Michigan, New Jersey, Maine, Pennsylvania, and Massachusetts have included such expenditures as stranded costs that can be recovered from electricity customers.
- Costs to Retire Debt and Capital: These costs include the costs associated with paying down the principal and interest of the existing loans.

Table 7 below provides an historic accounting of stranded costs that have been approved by regulators in states that have restructured.

Table 7: Stranded Costs Authorized for Recovery from Customers in Restructured States[172]

State	Utility	Total Stranded Costs ($ millions)	¢/kWh [173]
California	Pacific Gas & Electric	$5,640.0	7.4
California	San Diego Gas & Electric	$700.0	4.0
California	Southern California Edison	$2,500.0	3.3
Connecticut	Connecticut Light and Power	$1,440.0	4.8
Illinois	Commonwealth Edison	$3,400.0	3.7
Massachusetts	Boston Edison (NSTAR Electric)	$1,400.0	8.3

172 Source: Regulatory Research Associates, "Utility Asset Securitization in the U.S.," March 4, 2013. Supplemented by Concentric research.

173 The kWh equals the five-year average of the utility's sales prior to the first year of authorized stranded costs. For utilities for which stranded costs authorization was provided in multiple proceedings, Concentric used the five-year kWh average from the first authorization date.

State	Utility	Total Stranded Costs ($ millions)	¢/kWh [173]
Massachusetts	Western Mass Electric	$150.0	3.1
Michigan	Consumers Energy	$470.0	1.2
Michigan	Detroit Edison	$1,750.0	3.3
New Hampshire	Public Service Co. of New Hampshire	$1,210.0	8.7
New Jersey	Public Service Gas & Electric (PSEG)	$2.65	5.8
New Jersey	Atlantic City Electric (ACE)	$0.47	5.2
New Jersey	Jersey Central Power & Light	$0.502	2.4
New Jersey	Rockland Electric	$46.0	3.1
Pennsylvania	PECO Energy	$5,000.0	8.8
Pennsylvania	PPL Electric	$2,400.0	6.5
Pennsylvania	West Penn Power	$700.0	3.1
Texas	CenterPoint Energy Houston Electric	$4,780.0	6.5
Texas	AEP Texas Central Co.	$3,380.0	14.8
Texas	Oncor	$1,290.0	1.3

Stranded costs were also considered in Nevada in the context of the recent ballot initiative to restructure that state's electric market.[174] During the Public Utility Commission of Nevada's investigation of the proposal, NV Energy submitted several reports and comments that outlined the risks involved with restructuring, including stranded costs. NV Energy estimated that stranded costs would range from $5.18 billion to $6.13 billion, the majority of which related to retiring baseload generation.[175]

B. Stranded Cost Recovery

The most common stranded cost recovery mechanism is a "transition charge," which may be referred to as competition transition charge ("CTC") or a market transition charge ("MTC"). A transition

[174] Energy Choice Initiative Final Report, Investigatory Docket No.17-10001, PUC of Nevada.
[175] Final Comments, Nevada Power Company NV Energy and Sierra Pacific Power Company, Docket No.17-10001, page 1.

charge is an additional charge added to customer's bills that provides for the payment of the stranded costs incurred as a result of restructuring. Typically, the charges are based on actual energy use as a per kWh or kilowatt ("kW") charge, rather than applied as a flat rate to all customers and are non-bypassable. Table 8, below, summarizes stranded costs recovery mechanisms in use in restructured states.

Table 8: Examples of Stranded Cost Recovery Mechanisms[176]

State	Name	Recovery Adjustment Mechanism Description
Connecticut	Competitive Transition Assessment ("CTA")	IOUs were permitted to recover, through a CTA (1) above-market generating plants recognized in rates before the restructuring bill passed, (2) regulatory assets recognized a year after the restructuring bill was passed; and, (3) non-utility generation contracts entered into before the stranded costs proceeding began.
Delaware	Non-residential Wire Charge	Delmarva Power divested most of its generation assets, and the Delaware Commission authorized the recovery of $16 million of stranded costs through a non-residential surcharge.[177]
Illinois	CTC	Commonwealth Edison recovered stranded costs through a non-by-passable CTC that varied periodically with the market price of power.
Maine	CTC	The stranded costs were re-set every two-to-three years with periodic "true-ups" until the stranded costs were fully recovered.
Massachusetts	Transition Charge	The Massachusetts Department of Public Utilities approved company-specific transition plans, and virtually all generation assets were divested. The utilities were permitted to recover stranded costs through a transition charge.
Michigan	Public Act (P.A.) 141 and P.A. 142 in 2000 P.A. 286 in 2008	The 2000 and 2008 legislation provided for full recovery of PSC-approved stranded costs.
Montana	CTC	Northwestern has a CTC adjustment mechanism in place in its rates. This rider allows the company to recover restructuring-related out-of-market costs for certain power purchase contracts.
New Hampshire	Stranded Cost Recovery Charge ("SCRC")	The PSNH Proposed Restructuring Settlement allowed for recovery through the SCRC.
New Jersey	Market Transition Charge ("MTC")	New Jersey utilities recover stranded costs through a market transition charge. This MTC is a four-to-eight-year adjustment mechanism that allows the utility to recover stranded costs, though the amount changes based on market prices and customer demand.[178]

[176] EIA Status of Electric Industry Restructuring Activity (as of February 2003); http://www.energymarketers.com/Documents/Status_of_Electricity_Deregulation.htm, and Concentric research of state utility dockets.

[177] Delmarva was permitted to recover a maximum of $50 million on a system-wide basis but only $16 million through the non-residential wire charge (Docket 99-163, Order, August 31, 1999, page 5).

[178] 2013 New Jersey Revised Statutes, Section 48:3-61 – Market transition charge for stranded costs.

State	Name	Recovery Adjustment Mechanism Description
New York	N.A.	The NY PSC did not adopt a generic adjustment mechanism for cost recovery; instead, they approved plans on a company-by-company basis.
Ohio	Senate Bill 3	Stranded cost recovery extended to at least year-end 2005 for generation-related assets, and to year-end 2010 for regulatory assets.
Pennsylvania	CTC	The law permitted stranded cost recovery through competition transition charges, or CTCs. The CTC is now expired.
Rhode Island	Transition Charge	A non-by-passable transition charge for the recovery of generation-related stranded costs is to be collected from all distribution customers through December 31, 2029.
Texas	CTC	As part of the 1997 legislation, Texas established a "true-up" mechanism whereby the restructured utilities would recover stranded costs through a CTC.

Securitization of associated stranded costs is part of a broader, often negotiated arrangement allowing utilities to recover the difference between the market and book value of assets and power contracts. Securitization involves recovery of clearly defined and known costs through bonds that are issued by a special purpose entity ("SPE") and have highly certain cost recovery in rates and thus achieve a high credit rating with low associated financing costs. The securitization allows utilities to reduce the cost of capital by financing stranded costs with non-recourse debt (meaning the bond holders will have no right of claims against the utility) rather than a combination of debt and equity. The bond payments are typically recovered through a transition charge or a separate generation rider.

A critical element of the securitization mechanism is to establish a sound legislative and regulatory framework for recovery of specified dollars, i.e., a framework that reduces/eliminates lender risk of future judicial and regulatory modifications to the recovery of debt payments.

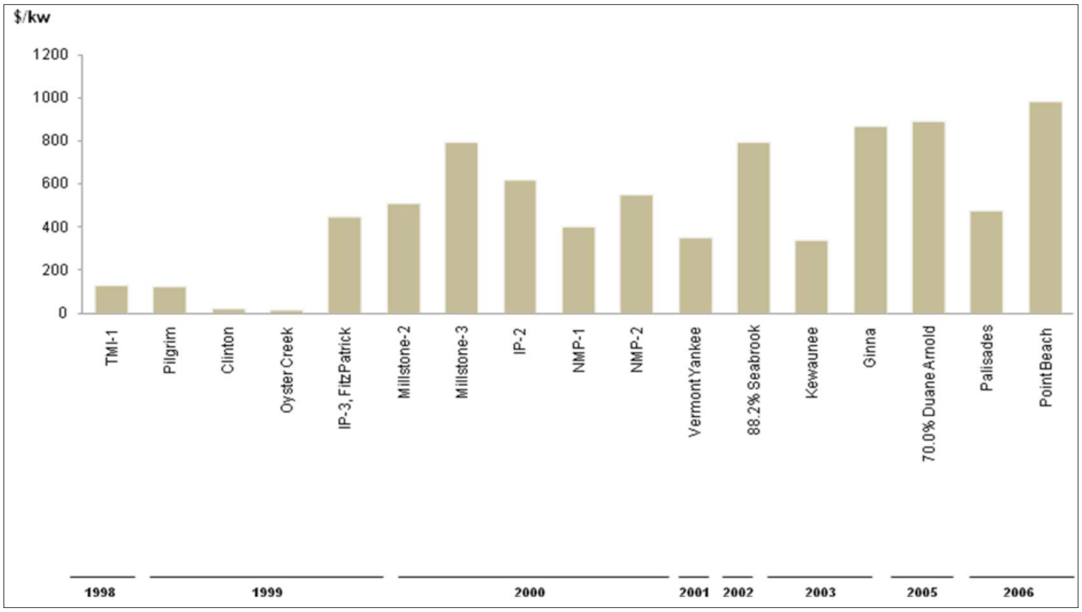
C. Other Considerations

In addition to stranded costs, the impact on municipal property taxes has resulted in significant legal challenges and attempted changes to property valuation. For example, Merrimack Station in Bow, New Hampshire represented nearly 14% of the town's taxable property. Prior to the sale of the plant, Eversource pursued in court and had the plant's value decreased by roughly 60% again by citing market value. The town attempted to appeal this decision with the New Hampshire Supreme Court and lost. The Court upheld the abatement exposing Bow to as much as $14 million in tax refunds.

D. Unique Considerations for Nuclear Generation

Nuclear assets in restructured states face unique challenges. In the early years of retail restructuring, nuclear power plants that were divested had very low market values and substantial stranded costs. Over time, nuclear plant valuations increased substantially as more utility owners sought to sell their nuclear interests for strategic (i.e. not restructuring-mandated) reasons.

Figure 22: Historical Nuclear Plant Sales ($/kW)[179]



More recent transactions involving nuclear power plants have resulted in their decommissioning.

Table 9: Recent Nuclear Plant Transactions[180]

	Oyster Creek	Palisades	Pilgrim	Vermont Yankee
Announcement Date	7/31/2018	8/1/2018	8/1/2018	11/8/2016
Purchaser	Holtec	Holtec	Holtec	NorthStar
Seller	Exelon	Entergy	Entergy	Entergy
Sale Price	Nominal	Nominal	Nominal	Nominal
Transaction Closing	3Q 2019	2019	2022	4Q 2018

Competitive wholesale electricity markets "focus on short-run marginal costs, with no reflection of fixed generating costs or returns on investment for generators."[181] Generation from nuclear units does not lend itself to marginal cost pricing. As a result, nuclear units have failed to clear in forward capacity auctions, despite the fact that the cost of continuing to operate existing nuclear units is lower on a levelized basis than the cost of building new gas-fired units to replace the capacity and energy lost when nuclear units retire early.[182]

These conditions have contributed to the early shut down of a number of nuclear plants and can be expected to continue to lead to more early retirements in the absence of other interventions. The merchant nuclear industry's struggles have been addressed through policy in several states that recognized the value of nuclear generation (i.e., high reliability, carbon-free emissions profile and

179 Concentric analysis. Data sources include transaction specific information that has been made available in state public utility regulatory commission filings and orders, by the Nuclear Regulatory Commission ("NRC"), or in company-specific Securities and Exchange Commission ("SEC") filings, investor presentations and press releases.

180 *Ibid.*

181 Idaho National Laboratory, *et al*. "Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet – Cost and Revenue Study." September 2017.

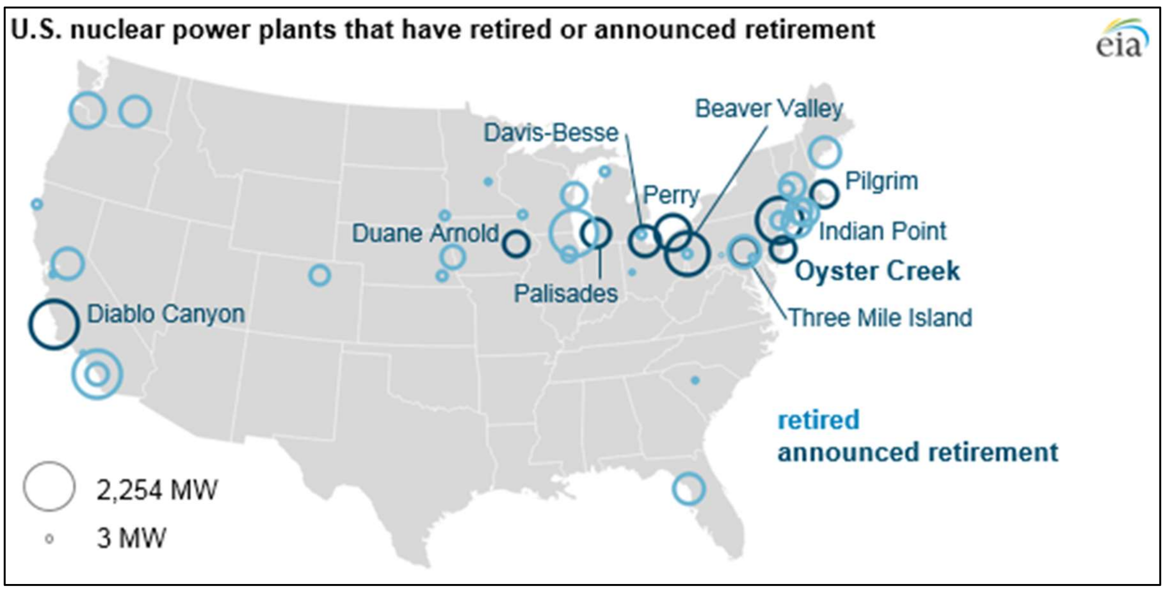
182 *Id.*

economic contribution to states, etc.) that was not being properly valued through existing market mechanisms. For example, in 2016 New York established a Clean Energy Standard that created ZECs. Under New York's 12-year plan, merchant nuclear generators will earn ZECs at a rate based on the social cost of carbon and prevailing market conditions. Recent analysis in a lawsuit opposed to the ZEC program estimates that, over its 12-year life, ZECs are estimated to cost as much as $7.6 billion.[183]

Illinois instituted a ZEC program comparable to New York's through the 2016 Future Energy Jobs Bill. The Illinois ZEC program will have an expected annual cost of approximately $235 million to support the Clinton and Quad Cities nuclear stations.[184] Pennsylvania is currently considering a similar legislative fix. The Connecticut legislature passed a measure in 2017 that made the Millstone nuclear plant eligible for the state's competitive clean energy procurement, which provides a similar subsidy for carbon-free energy but is not nuclear-specific.[185]

As shown in Figure 23, below, the U.S. is seeing significant retirement in its nuclear fleet, particularly in states that have restructured their electricity markets.

Figure 23: U.S. Nuclear Plant Retirements[186]



183 Power Markets Today, "Generators sue New York PSC over new ZEC Charges," (Oct. 20, 2016).

184 Utility Dive, "Updated: Federal Judge dismisses challenge to Illinois nuke subsides," (July 17, 2017).

185 PURA, State of Connecticut, Docket No. 18-05-04, Interim Decision, Millstone Power Plant. (Dec. 5, 2018).

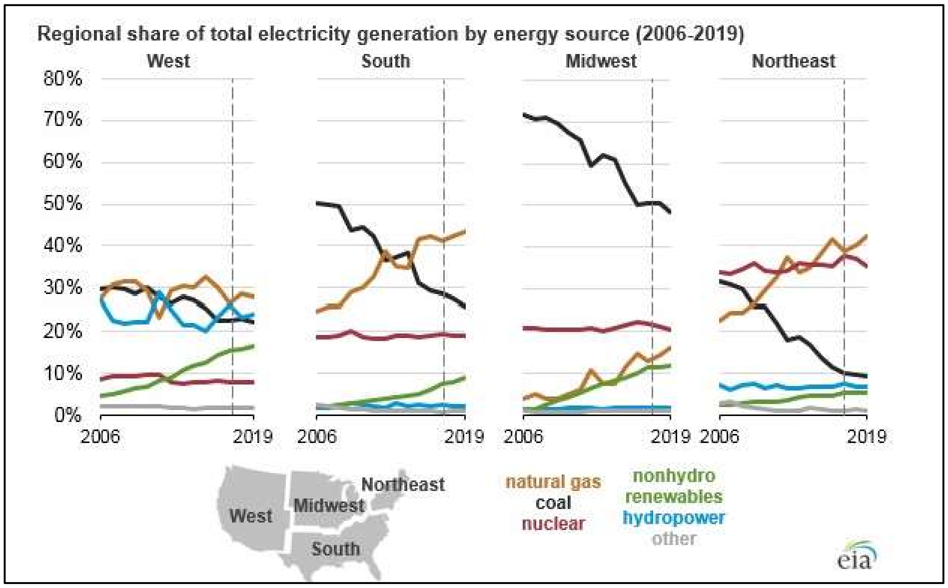
186 US EIA, Today in Energy, "America's oldest operating nuclear power plant to retire on Monday," (Sept. 14, 2018).

IX. Transition in Generation Fleet

A. Transition in U.S. Generation Fleet

Recent decades have seen a dramatic shift in the U.S. generation fleet. Changes in the generation mix have been driven by very low natural gas prices and the growing importance of renewable resources. The resulting low wholesale electric prices, coupled with other cost pressures, have challenged the economics of traditional baseload generation like coal and nuclear units. These units have been replaced primarily by natural gas, wind and solar generation in both restructured and traditionally regulated markets as shown in Figure 24, below.

Figure 24: Trends in Electric Generation by Energy Source by Region [187]



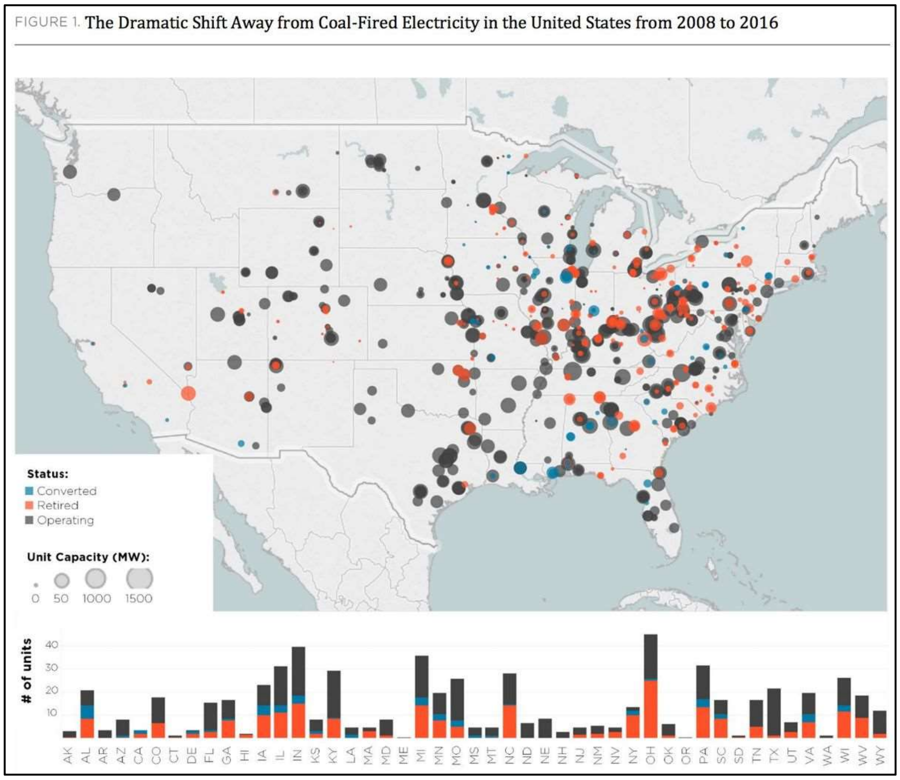
2. Retirement of Coal and Nuclear Generation

Coal plant retirements are ubiquitous across the U.S., including both restructured and traditionally regulated markets, driven by environmental considerations/the cost of environmental controls and the shift in wholesale market prices. While a majority of these units have retired for economic reasons, other influential factors include federal and state policies that require or encourage the use

[187] Ibid.

of non-carbon emitting generating resources. Figure 25 illustrates the nationwide trend in coal retirements.

Figure 25: US Coal Retirements[188]



The coal plants that have retired over the past decade have largely been over 50 years old. The remaining coal plats still in operation are approximately 40 years old.

As described above, nuclear units have also faced challenges to their economic viability, resulting in the closure of many of these units.

For generating resources operating in competitive markets, the generator owner receives compensation in the wholesale market for the products and services it provides. In contrast, a utility in a vertically integrated market would likely recover their cost of generation through cost of service rates, that allow for recovery of plant costs in the short term. Over time, the cost pressures, including the availability of lower cost alternatives such as natural gas and wind and cost for environmental controls, have impacted generation portfolios in traditionally regulated markets just as they would in restructured markets. Therefore, it is perhaps not surprising that coal retirements are ubiquitous across the U.S., including both restructured and non-restructured markets.

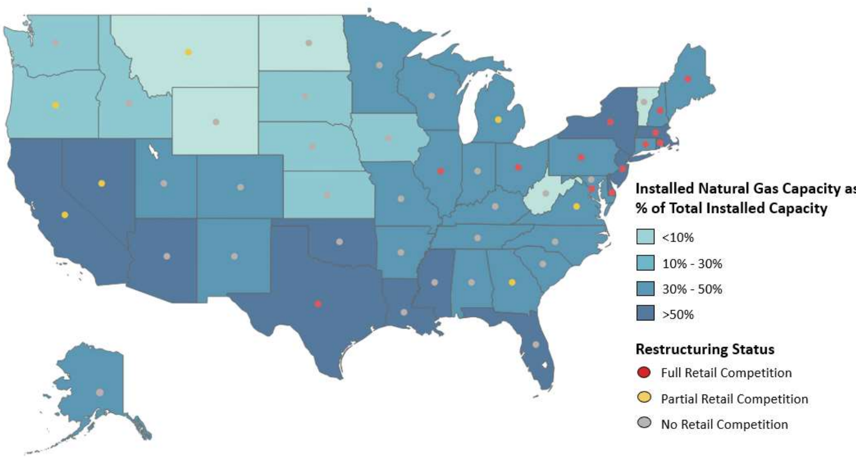
Nuclear units have faced similar challenges to their economic viability. Cheap natural gas and renewable energy, rising operational costs, and safety and performance concerns have all threatened the profitability of nuclear power plants, and resulted in the closure of many of these units.

188 David Roberts, "4 signs that Trump's furious efforts to save coal are futile" VOX, Jan. 30, 2018.

3. Growth in Natural Gas

Natural gas prices have been relatively low due to soaring U.S. production of shale gas in the Northeast, Texas and the Midwest. These low natural gas prices have resulted in a growth in natural gas-fired generation. Figure 26, below, shows that development of natural gas generation is pervasive across the US, in both restructured and traditionally regulated states. Of the states where natural gas fired power plants represent more than 30% of total installed capacity, 20 have no retail competition, 5 have partial retail competition, and 13 have full retail competition.

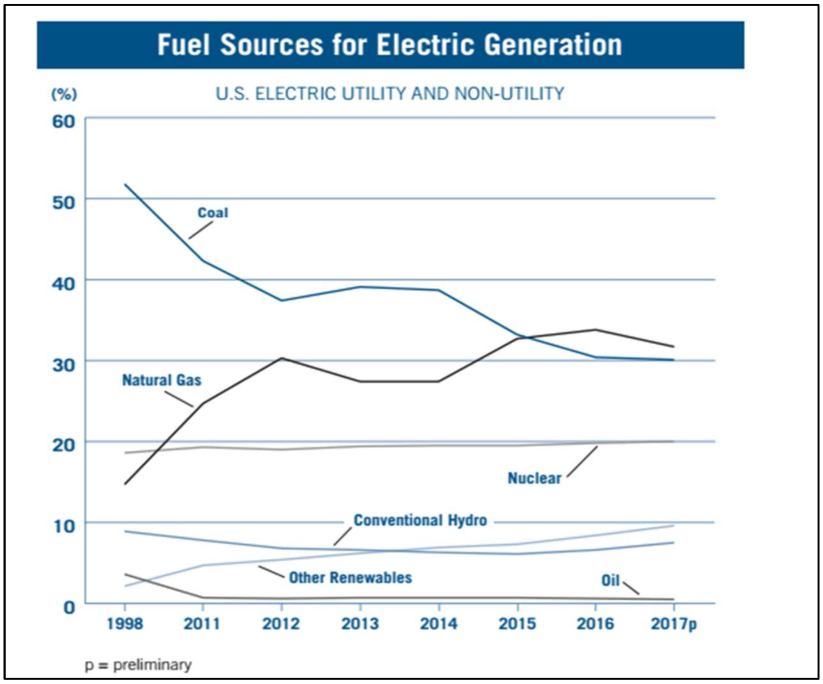
Figure 26: Total Installed Natural Gas Electric Generating Capacity [189]



To illustrate the dramatic decrease in natural gas prices, as recently as June 2009, natural gas was trading at over $12 per MMBtu. Since early 2015, NYMEX natural gas contract settlement prices have consistently been in the $2.50 - $3.50 per MMBtu range. As a result, natural gas has surpassed coal as the highest fuel source for electric generation in the U.S., as shown in Figure 27, below.

[189] EIA Form 860 2018 Preliminary Data – Schedule 3, 'Generator Data' (Operable Units Only).

Figure 27: Fuel Sources for Electric Generation[190]



a. Relationship Between Fossil Retirements, Growth of Natural Gas and Restructuring Status

A study by the U.S. DOE Lawrence Berkeley National Lab examined factors that led to the large-scale retirement of fossil units and concluded that it was not "obvious" that "the recent growth in thermal plant retirements is affected by whether the region has a wholesale market overseen by an ISO. SERC is traditionally regulated and has among the highest amount of retirement of all regions. The WECC (not including California) and FRCC also remain under traditional regulation but have experienced relatively lower levels of retirement so far. Among the many regions with ISOs, retirement percentages vary widely." [191] Similar, the aforementioned analysis by O'Conner and Kahn noted "In both the [states without retail competition] and [states with full retail competition] groups, there has been a substantial shift in electricity production fuel mix from coal toward natural gas. In this respect, the trends in both groups have been similar."[192]

4. Growth in Renewable Generation

Another significant trend has been the growth in renewable generation. Figure 28 shows the deployment of wind generation across the US to date.

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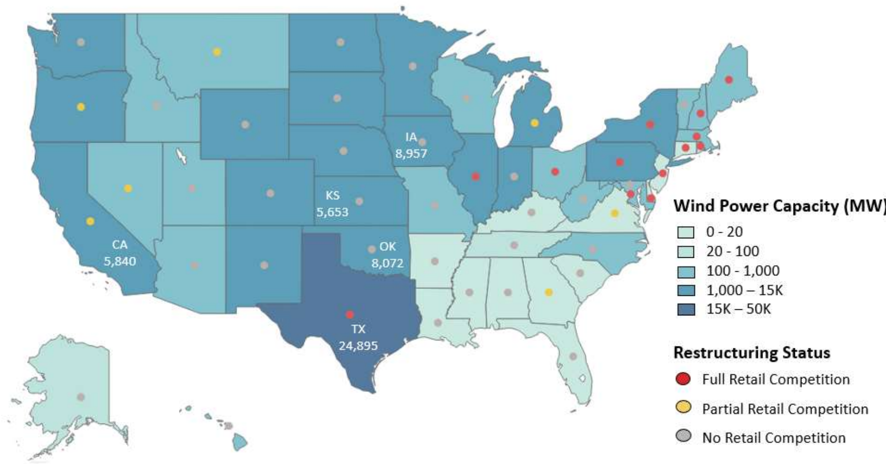
190 Edison Electric Institute 2017 Financial Review, page 64. Data sourced from EIA, US Department of Energy.

191 Mills, Andrew, Wiser, Ryan, Seel, Joachim, "Power Plant Retirements: Trends and Possible Drivers," Lawrence Berkeley National Laboratory, November 2017, page 11.

192 O'Connor and Khan, page 7.

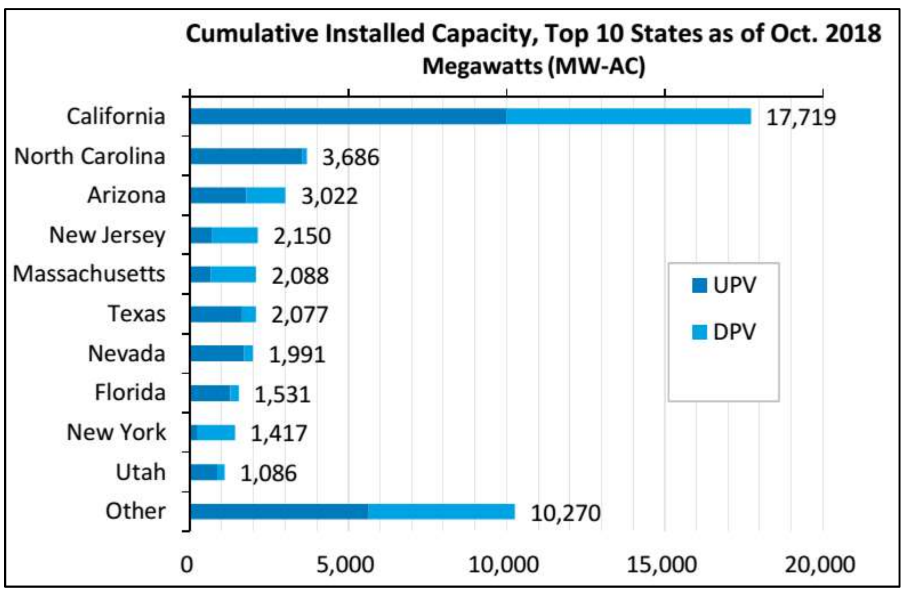
Figure 28: US Installed Wind Power Capacity[193]



As shown above, the top five states in terms of installed wind capacity are Texas, Iowa, Oklahoma, California and Kansas, three of which do not have retail competition.

While wind is generally a wholesale power resource, solar energy can be either a distributed energy resource or a utility scale. Figure 29 shows the top ten states in level of solar PV generation, including both utility scale and distributed.

Figure 29: Top 10 US States in Cumulative Installed PV Solar Capacity[194]



As these snapshots of wind and solar penetration illustrate, these resources are deployed in both restructured and traditionally regulated states. As noted in the analysis by O'Connor and Kahn, "trend lines for wind and solar together have been nearly identical in both groups of states [i.e., with and without full retail competition], rising from a negligible position in 1997 to more than 7% in 2017."[195]

193 Map adapted from U.S. Department of Energy map and data: https://windexchange.energy.gov/maps-data/321

194 National Renewable Energy Laboratory, "Q3/ Q4 2018 Solar Industry Update" January 2019, p. 26. "UPV" stands for utility-scale PV and "DPV" stands for distributed PV.

195 O'Connor and Khan, page 8.

Many states with significant deployment of wind are not in restructured areas, and there are solar resources that are located in states that are vertically integrated but sell into competitive markets. Many of the leading US states with solar deployment are either not restructured or have only partially restructured. Arizona is among the national leaders in solar generation, ranking third among US states.

The deployment of renewable resources is influenced by locational characteristics or policy mandates. This is illustrated by the significant development of wind resources in mid-western/ western states and solar resources in states like Arizona, Florida, and Nevada. (Some states, such as Massachusetts, New York, and New Jersey, have developed a relatively significant amount of solar resources, due to policy support for solar PV through generous net metering and RPS or other programs subsidies, rather than restructured markets.)

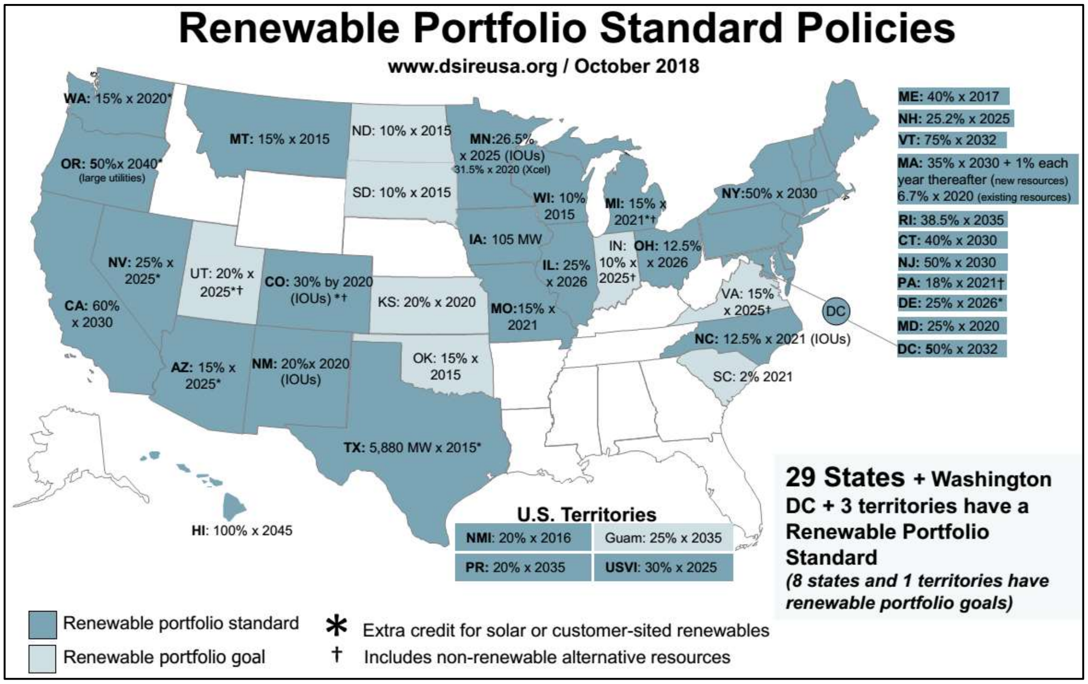
The broad expansion of solar generation in restructured and traditionally regulated states alike illustrates that the transition of the generating fleet, including distributed resources, to becoming cleaner and more efficient, is determined by numerous factors.

B. Federal, State, and Local Policy

Energy policies (other than restructuring policy) at numerous levels have supported the transition of the electric generation fleet. Federal tax credit policies have helped to drive large-scale wind and solar deployment in particular (the production tax credit for wind and the investment tax credit for solar).

Most states have policies that support the development of energy resources that contribute to the transition of the electric generation fleet. Many states have renewable portfolio standards ("RPS"), which drive and support the development of renewable generation resources. Currently, 29 states, Washington DC, and three territories have an RPS, and eight states and one territory have renewable portfolio goals. These are shown in Figure 30, below. Similarly, many states have state specific GHG reduction goals, and/ or participate in regional GHG reduction regimes such as the Regional Greenhouse Gas Initiative in 10 northeastern states.

Figure 30: US Renewable Portfolio Standards and Goals.[196]



C. Cost Declines in Energy Resources

Perhaps the most significant driver in transition of the electric generation fleet has been cost declines in generating resources. Similar to the impact of shale gas on the growth of natural as generation, cost declines in wind and solar PV have supported their broad scale deployment, as shown in Figure 31 and Figure 32, below.

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196 North Carolina Clean Energy Technology Center, US DOE Energy Efficiency and Renewable Energy. October 2018.

Figure 31: Wind PPA Prices[197]

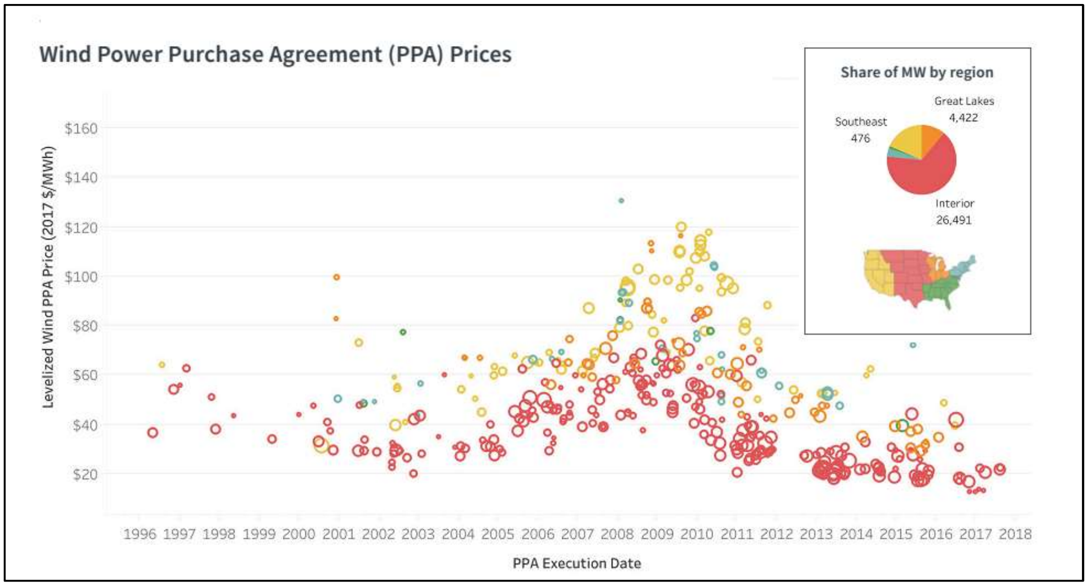
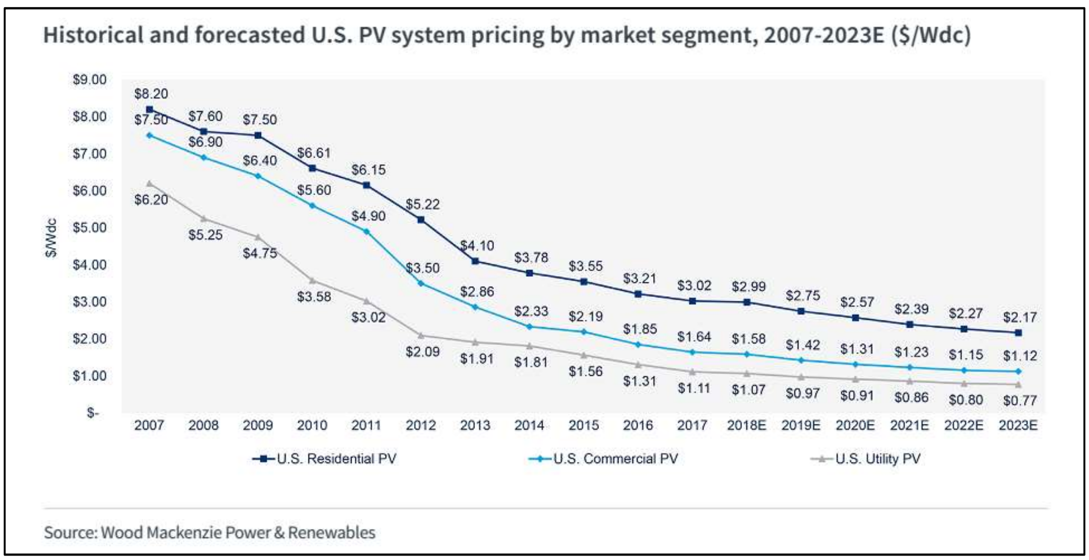


Figure 32: Declining Solar PV System Pricing[198]



Finally, it is important to note cost dynamics apply and are addressed in traditionally regulated states as well as in restructured states. Regulators, other policy makers, stakeholders, and utility managers in traditionally regulated states have the same information regarding costs, environmental impacts, customer preferences and so on, as in other states, and so can and do make determinations to transition generating fleets.

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[197] Cohn Reznick, "2019 Trends in Utility Renewable Energy Finance," page 2, citing "2017 Wind Technologies Market Report," Source: Berkeley Lab.

[198] Cohn Reznick, "2019 Trends in Utility Renewable Energy Finance," page 3, Source: Woods McKenzie Power & Renewables.

X. Restructuring and Innovation

A. Introduction

Fostering innovation is among the goals cited by advocates of restructuring. In 2000, the U.S. EIA stated: "Competitive industries may also be more likely to spur innovations with new technologies." [199] In 2002, the U.S. Government Accountability Office stated that, "Competition is expected to produce benefits… by encouraging innovations in retail electricity services." [200]

This chapter identifies several of the key innovations in the electric sector over the past 20 years and conducts a high-level review of the level of adoption or penetration of the innovation or advancement across restructured and non-restructured states. The innovations involve new technologies or new products and services. This review does not quantify the impact of restructuring or traditional regulation, but rather provides a discussion of how or if the decision to restructure may have been influential on the level of innovation. This analysis is meant to be informative to policy makers exploring the question of whether adopting restructuring and retail competition is necessary to foster innovation. As discussed in the sections of this chapter which follow, the research conducted does not show definitive evidence that innovation is hindered in states with traditionally regulated electric markets.

This chapter identifies and discusses the following innovations: (1) innovative pricing products; (2) advanced metering infrastructure; (3) green energy products; (4) energy storage; (5) electric vehicles, and (6) microgrids.[201] The overall conclusion of this high-level review is that while industry structure may play a role, there are numerous factors that support electric sector innovation, including broader state policy. Indeed, there is meaningful adoption of all these innovations both in restructured and non-restructured environments.

1. Innovative Retail Pricing Products and Associated Metering Infrastructure

Innovative price offerings for retail electric service have been in place for many years in all types of electric markets. There are several possible categories for innovative retail pricing and products. Innovative pricing is loosely defined as a rate option or design that transcends traditional electric pricing components.

Traditional components include:

- **Distribution:** A fixed customer charge and a volumetric delivery charge;
- **Transmission:** A volumetric charge, and

199 NESCOE Report, page 7, citing, US DOE EIA "The Change Structure of the Electric Power Industry 2000: An Update" October 2000.

200 NESCOE Report, page 8, citing US Government Accountability Office, "Lessons Learned from Electricity Restructuring - Transition to Competitive Markets Underway, but Full Benefits Will Take Time and Effort to Achieve." (December 2002) page 21.

201 While not used as an authoritative source for this selection of key innovations, this list bears significant alignment with two recent industry listings regarding innovative electric sector activity: Bede, Gavin, Utility Dive, "The top 10 trends transforming the electric power sector" (Sep. 17, 2015); Girouard, Coley, Advanced Energy Economy, "Top 10 Regulation Trends of 2018 – So Far" (July 18, 2018).

- **Energy:** A volumetric charge.

These components may be complemented by several rate riders, such as decoupling, transition surcharges, federally mandated congestion charges, conservation program charges, etc.

"Innovative" pricing options include:

Demand Pricing: Demand pricing includes a charge based on a customer's peak demand (expressed in kW) during a prescribed period. The period may be annual, seasonal, or based on the time of day.

Time of Use ("TOU") Pricing: TOU pricing charges customers a different volumetric rate at different times of the day. A simple TOU structure will have defined "on-peak" and "off-peak" hourly periods, such as 8:00AM – 8:00PM (on-peak) and 8:00PM to 8:00AM and weekends (off-peak).

Critical Peak Pricing ("CPP"): Critical peak pricing established another TOU rate block based on a smaller time interval, intended to match the utility's peak hour(s) of demand. An example of CPP would be a TOU rate design with a critical peak price between 4:00PM and 6:00 PM.

Real-Time Pricing ("RTP"): RTP rates are typically reserved for large C&I customers. This rate design allows customers to participate directly in wholesale markets (usually both current day and day-ahead markets). RTP Tariffs tend to be restrictive whereby minimum demand requirements are established, as well as maximum tariff subscription amounts.

Another element of innovative pricing is customer rate choice. Customer rate choice means that certain pricing schedules are optional. Options include:

Opt-in: Opt-in rate choice provides an optional rate schedule that customers can evaluate and then decide if the potential risks of that rate schedule are worth the potential cost savings. TOU rates are often designed as an opt-in rate.

Opt-out: Opt-out rate choice is another optional rate schedule that, unlike opt-in, customers are assigned to the new rate and customers must elect to be placed back on a traditionally priced rate schedule.

Subscription: Subscription rates are opt-in rates with a total program limitation. This is used often for RTP and economic development rates, or residential solar PV pilot programs.

Several states have introduced innovative pricing concepts. For example:

Alabama and **Georgia:** The Alabama Power Company (a wholly-owned subsidiary of the Southern Company) provides over 60 pricing options to its customers.[202] These pricing options are categorized into four main categories: Demand pricing, TOU Pricing, RTP and Miscellaneous (industry-specific pricing, such as farm service and cotton gins).

Arizona: APS, TEP and SRP have a comprehensive set of innovative pricing tariffs. These include opt-in residential TOU and demand rates, riders for solar PV, and "green choice" tariffs that allows customers to pay a premium for electricity generated from renewable resources.

Oklahoma: Oklahoma Gas & Electric ("OG&E") offers TOU pricing, guaranteed flat bill pricing, and variable peak pricing for Residential and General Commercial service. Although large users are not eligible for the guaranteed flat bill, they can participate in RTP tariffs.

[202] https://www.alabamapower.com/business/rates-and-pricing/about-our-pricing.html

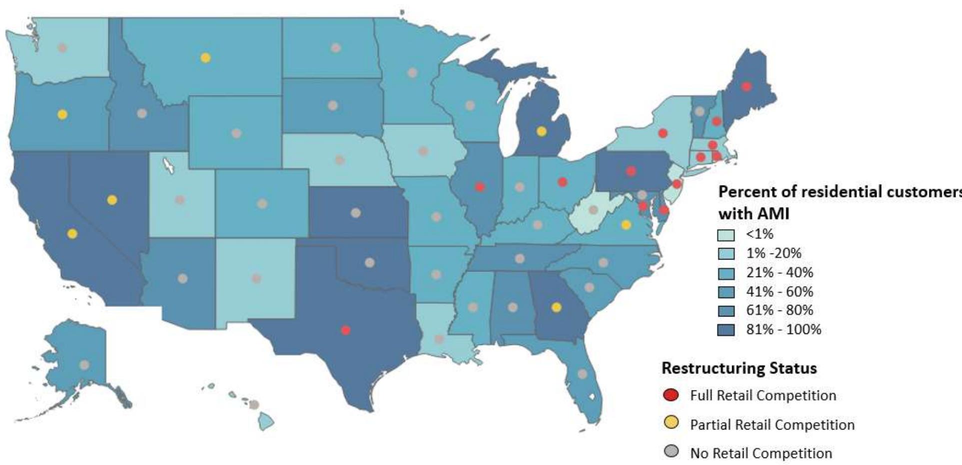
Wisconsin: WEC Energy's Wisconsin Electric Power Company ("WEPCO") and Wisconsin Public Service Corporation ("WPSC") both offer substantial RTP programs as well as economic development tariff opportunities to its largest C&I customers.

2. Advanced Metering and Time Varying Rates for Residential Customers

Perhaps the most prevalent form of customer-facing innovation today is smart metering and related systems and technology, generally referred to as automated metering infrastructure ("AMI"). AMI is often considered a foundational investment to unlock customer-sited innovation, enabling real-time two-way flow of meter, cost, and other energy data, supporting efficiencies in meter reading and customer communication, facilitating the integration of customer sited distributed energy resources ("DERs"), and advancing reliability and resiliency.

Figure 33 below shows the level of AMI deployment across the U.S. as of 2016. As this shows, smart meter deployment is spread across the country, and, in fact, several restructured states do not have AMI or have relatively low levels of smart metering deployment. Of the states where more than 70% of customers have AMI, eight are traditionally regulated and five are fully restructured.

Figure 33: Residential Smart Meter Adoption Rates[203]



One factor contributing to this low level of AMI in some restructured states is directly attributable to retail restructuring, as is illustrated by a recent proceeding on AMI in Massachusetts.

In a recent order rejecting utility AMI proposals, the Massachusetts Department of Public Utilities ("DPU") found that "primary benefits of advanced metering functionality are derived from reduced peak usage as customers respond to pricing signals" that are time-varying and dynamic.[204] However, because Massachusetts is a restructured retail market, the DPU only has authority over energy pricing for the utility POLR service. As such, the DPU determined that if it were to order that the utility POLR service be transitioned to a time varying, dynamic pricing structure, it is likely that customers

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[203] Map adapted from: US EIA "Today in Energy – Nearly Half of All US Electricity Customers have Smart Meters," Dec. 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=34012.

[204] Mass. Department of Public Utilities, Order D.P.U. 15-121, -121-122. (May 2018), page 2.

would switch to competitive suppliers who would continue to offer flat rate pricing.[205] Ultimately, the DPU was unable to find that AMI deployment - and the innovations it could enable - was cost effective, because customers could simply switch to simplistically-priced competitive offerings.

This contrasts with a very successful dynamic pricing program conducted by Oklahoma Gas and Electric ("OGE"), in which 100,000 of OGE's 625,000 residential and small business customers are enrolled.[206] OGE's dynamic pricing programs have cut OGE's average peak load of 5900 MW by 160 MW and reduced participating customers' contribution to peak by 40%.[207] Combined with energy efficiency and commercial-industrial peak reductions, OGE's peak load is down approximately 300 MW, which has allowed the utility to avoid new investment in thermal generation.[208] Moreover, according to the company, the average customer saved approximately $150 for the summer and satisfaction of people in the program is higher than that of standard customers.[209]

Ultimately time varying, dynamic pricing has the potential to drive change in customer behavior, including the optimal adoption and use of distributed energy resources and end uses, including solar PV, energy storage, demand response and conservation, electric vehicles, and heating and cooling with efficient electric heat pumps. However, restructuring can introduce challenges and complexities for policymakers, utilities, and stakeholders in providing such innovative pricing options to customers.

Figure 34 illustrates the level of residential customers on Time Varying Rates ("TVR") in U.S. states. Notably, many of the states with higher percentages do not have retail competition. This includes Arizona, which is a leading state in terms of residential customers on innovative rate options.

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205 The DPU wrote: "Achieving this benefit requires customers to participate in time varying rates or other dynamic pricing programs. As more customers migrate off of basic service to alternatives, such as municipal aggregation, the Department would need the certainty of wide adoption of dynamic pricing products from the competitive supply market to maximize the benefits of advanced metering functionality. Without such wide adoption, the Department lacks the needed assurance that the benefits associated with advanced metering functionality will justify the substantial costs." Order D.P.U. 15-121, -121-122. (May 2018), page 3.

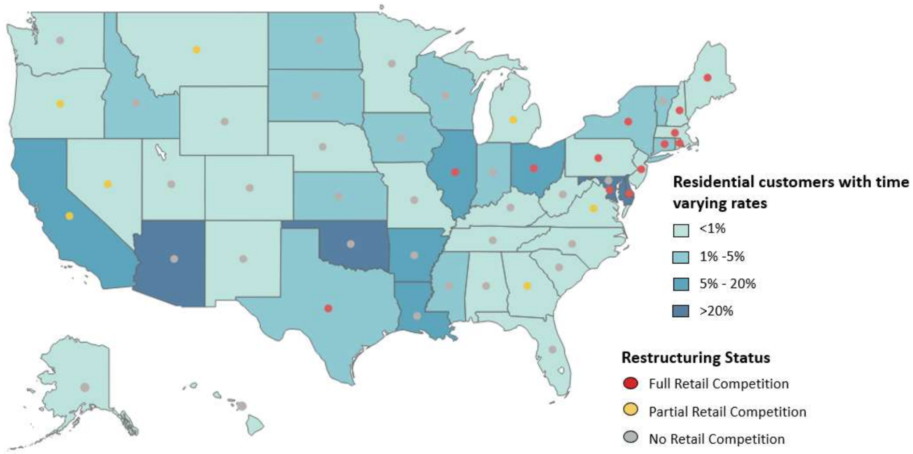
206 Herman K. Trabish, Utility Dive, "Beyond TOU: Is More Dynamic Pricing the Future of Rate Design." (July 17, 2017).

207 *Ibid.*

208 *Ibid.*

209 *Ibid.*

Figure 34: Residential Customers on Time Varying Rates [210]



3. Green Pricing Options

One important innovation in pricing is the offering to customers of energy products with greater percentages of renewable energy than other grid offerings. This often occurs through additional purchases and retirements of renewable energy certificates ("RECs") or other means (such as bundled REC and energy products based on contracts with specific renewable energy facilities). Figure 35, below identifies the range of approaches for green pricing products, with the top two categories representing utility offerings to customers. As this figure illustrates, these two utility options, as well as all other categories, show consistent growth from the period 2010-2016, demonstrating that such innovative products are in no way limited to competitive suppliers. The options, "Competitive suppliers" and "CCAs" represent competitive supply options, and "Community solar" may be a competitively provided or utility provided option.

[210] Map adapted from: Girouard, Coley, Advanced Energy Economy – Advanced Energy Perspectives "Top 10 Utility Regulation Trends of 2018 – So Far," July 2018, https://www.greentechmedia.com/articles/read/top-10-utility-regulation-trends-of-2018-so-far.

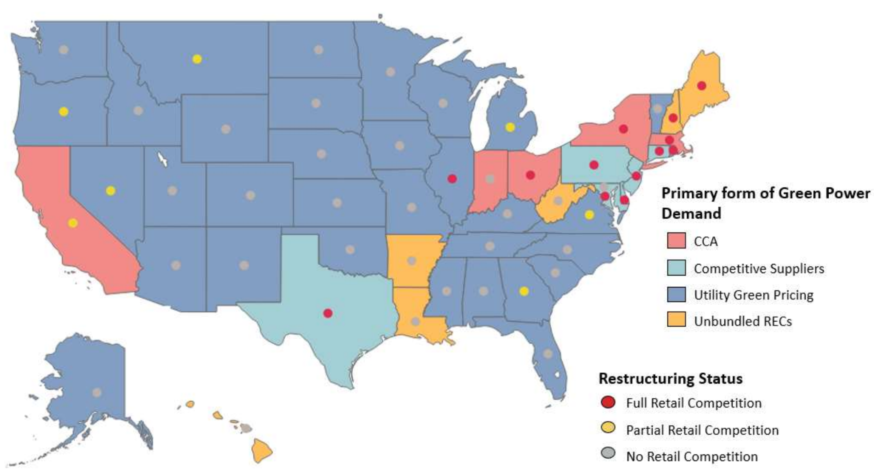
Figure 35: Estimated Green Power Sales (millions of MWh), 2010-2016a[211]

Green power option	2010	2011[b]	2012	2013	2014	2015	2016
Utility green pricing	5.4	5.8	6.0	6.9	7.0	7.5	8.0
Utility contracts	0	0	0	0.2	0.7	1.9	2.9
Competitive suppliers	10.4	11.0	11.6	14.5	16.2	15.4	16.0
Unbundled RECs	19.8	25.4	31.0	31.4	36.0	42.5	51.8
CCAs	-	-	-	8.1	7.7	7.4	8.7
PPAs	1.3	2.1	2.2	2.7	5.1	6.6	7.9
Community solar	0.005	0.050	0.080	0.100	0.150	0.180	0.260
Total[c]	**37**	**44**	**51**	**64**	**72**	**80**	**95**

[a] Historical results may differ from previous reports because of methodology adjustments; dashes indicate that reliable estimates for historical data are unavailable.
[b] Utility green pricing and unbundled RECs data were not collected for 2011. Estimates for 2011 are based on the midpoint between 2010 and 2012.
[c] The total does not include community solar outside of PG&E program (customers typically do not retain the RECs).

Figure 36, below, illustrates the primary form of green power demand (by number of customers) by state. As this shows, utility green pricing tends to be the dominant form in non-restructured states, whereas CCAs and Competitive Suppliers tend to be the primary form in restructured states. An important observation is that there is some form of green pricing product in almost all states, whether restructured and non-restructured.

Figure 36: Primary Form of Green Power Demand (number of customers) by State[212]



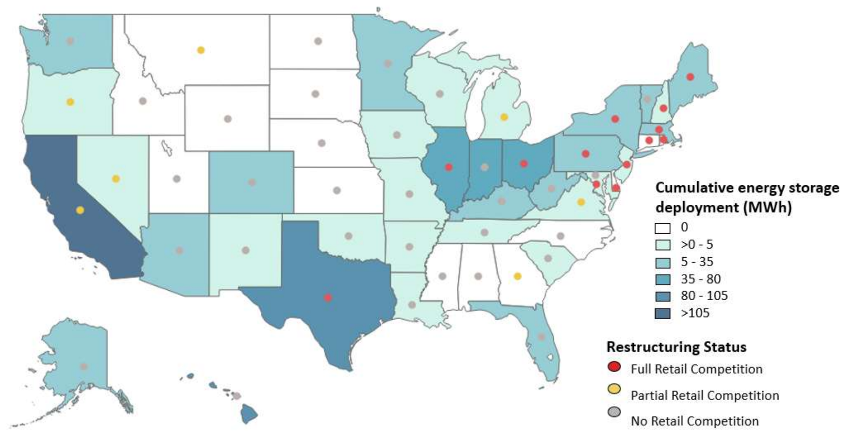
211 Eric O'Shaughnessy, Jenny Heeter, Jeff Cook, and Christina Volpi "Status and Trends in the U.S. Voluntary Green Power Market (2016 Data)" National Renewable Energy Laboratory (October 2017), page 5.

212 Eric O'Shaughnessy, Jenny Heeter, Jeff Cook, and Christina Volpi "Status and Trends in the U.S. Voluntary Green Power Market (2016 Data)" National Renewable Energy Laboratory (October 2017), page 40.

4. Energy Storage

One important innovative energy technology is energy storage. Figure 37 shows the cumulative battery storage deployment through 2018.

Figure 37: Cumulative Battery Energy Storage Deployment[213]



Energy storage can provide a variety of benefits, on the transmission and distribution system and customer premises. It can help to effectively integrate intermittent renewables resources, and provide benefits ranging from cost savings to reliability and resiliency. Figure 37 above shows that there is storage activity throughout the US, though it there may be relatively more in restructured states.

Notably however, some restructured markets in particular struggle with how to enable achievement of the full suite of benefits (sometimes referred to as the "value stack"). This occurs because restructuring statutes and rules often preclude a utility from owning generation and/ or bidding storage output as a resource in wholesale energy or capacity markets. A report by the DOE Sandia Labs describes this scenario whereby an energy storage resource would be able to "participate in the wholesale electricity market providing generation service and transmission congestion relief," but could not do so "while also earning cost of service recovery providing distribution service, despite the technical ability of a storage resource to provide this service."[214] This report notes that "[i]n non-ISO/RTO regions, a vertically integrated utility can utilize its assets for any purpose across these classifications and recover all value that the asset can provide."[215] This can represent a significant complication and barrier to the adoption of this potentially transformative resource and realization of its associated benefits. Traditionally regulated utilities that are allowed to own generation do not face such challenges in capturing and "stacking" the benefits of storage.

Texas provides an example of the challenge of storage deployment in restructured markets. In 2018, the PUCT dismissed a request by AEP Texas, a unit of American Electric Power, to install two battery storage projects, citing a lack of information to render a decision.[216] The PUCT then opened a

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213 Smart Energy Power Alliance, "2018 Utility Energy Storage Market Snapshot" (August 2018)

214 Bhatnager, Dhruv, Currier, Aileen, Hernandez, Jacquelynne, Ma, Ooke, and Kirby, Brenda, Sandia National Laboratories, "Market and Policy Barriers to Energy Storage Deployment" (September 2013), page 22.

215 Ibid.

216 Public Utility Commission of Texas, "Scope of Competition in Electric Markets in Texas, Report to the 86th Legislature." January 2019.

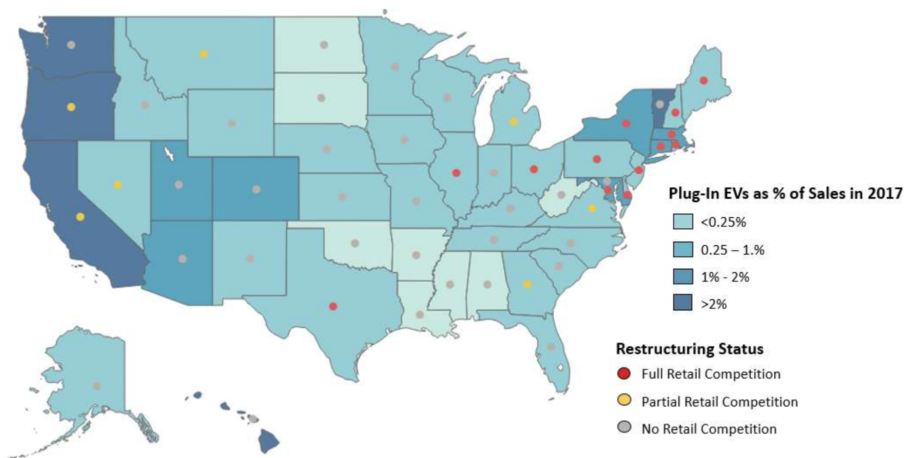
proceeding to establish a regulatory framework for such issues; however, the PUCT ultimately decided to defer the issue to the Texas legislature.[217] During the 2019 session, however, the Texas legislature did not pass legislation on this issue. According to a recent industry article, Texas has seen a disproportionally small amount of storage development, driven in part by these regulatory issues.[218]

Other factors also influence the deployment of storage. For example, FERC Order 841 requires ISOs and RTOs to develop rules for how storage can participate in their wholesale markets. Also, states such as California, New York, and Massachusetts have energy storage procurement requirements, which have or will support the deployment of energy storage.

5. Electric Vehicles

Electric vehicles represent an important innovation in the electric sector, including the promise to significantly decarbonize the transportation sector, a major contributor to US GHGs.

Figure 38: Electric Vehicles[219]



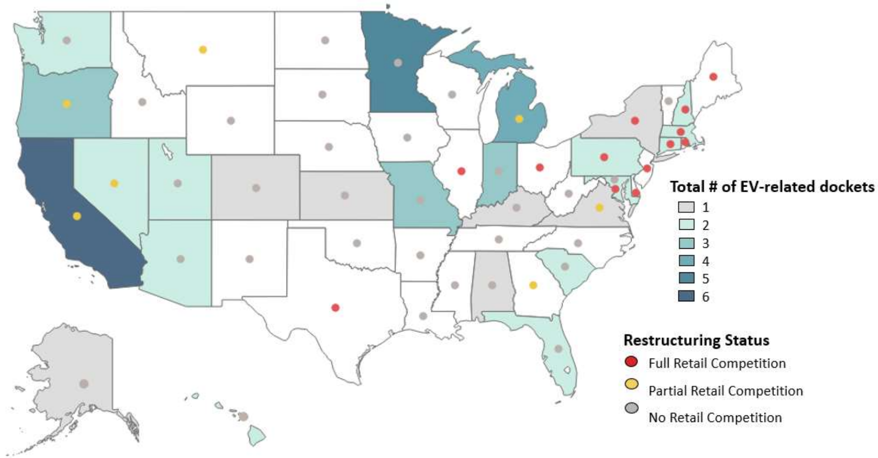
The adoption of EVs is largely driven by state policies, such as rebates for EV purchases. However, utilities often have a role, including supporting EV charging, ranging from Level 1 or Level 2 chargers at homes or businesses to fast charges on highways. One indicator of level of utility related innovation regarding EVs is whether a regulatory Commission has taken action to investigate and spur a potential utility role.

217 Maloney, Peter, "Texas regulators defer to legislature on utility ownership of energy storage." Utility Dive, January 18, 2019.

218 Maloney, Peter, "Texas regulators defer to legislature on utility ownership of energy storage." Utility Dive, January 18, 2019. "There are about 1,800 MW of energy storage project's in Texas' interconnection queue, but only a handful of storage projects have been put in place. And storage projects in Texas to date pale in comparison to the size of the market and the deep penetration of renewable resources in the state, which is often seen as creating an opportunity for energy storage to shift loads or store excess renewable generation."

219 Map adapted from: Smart Energy Power Alliance, "2018 Utility Energy Storage Market Snapshot," August 2018, Available here: https://sepapower.org/resource/2018-utility-energy-storage-market-snapshot/. (Data from UC Davis Plug-In Hybrid and Electric Vehicle Research Center).

Figure 39: Total Number of EV-Related Regulatory Dockets by State[220]



It should be noted that utilities in non-restructured states may perceive strong drivers to support EV deployment and make related infrastructure investments, such as EV chargers and EV charging "make-ready" investments in their service territories. Beyond public interest benefits that utilities may support including pollution reduction and customer satisfaction, utilities, particularly those in traditionally regulated states may perceive EVs as "beneficial electrification," whereby through sending appropriate price signals to incent off-peak charging, utilities can optimize existing infrastructure, increasing sales during off-peak rates, and thus reducing rate pressures.

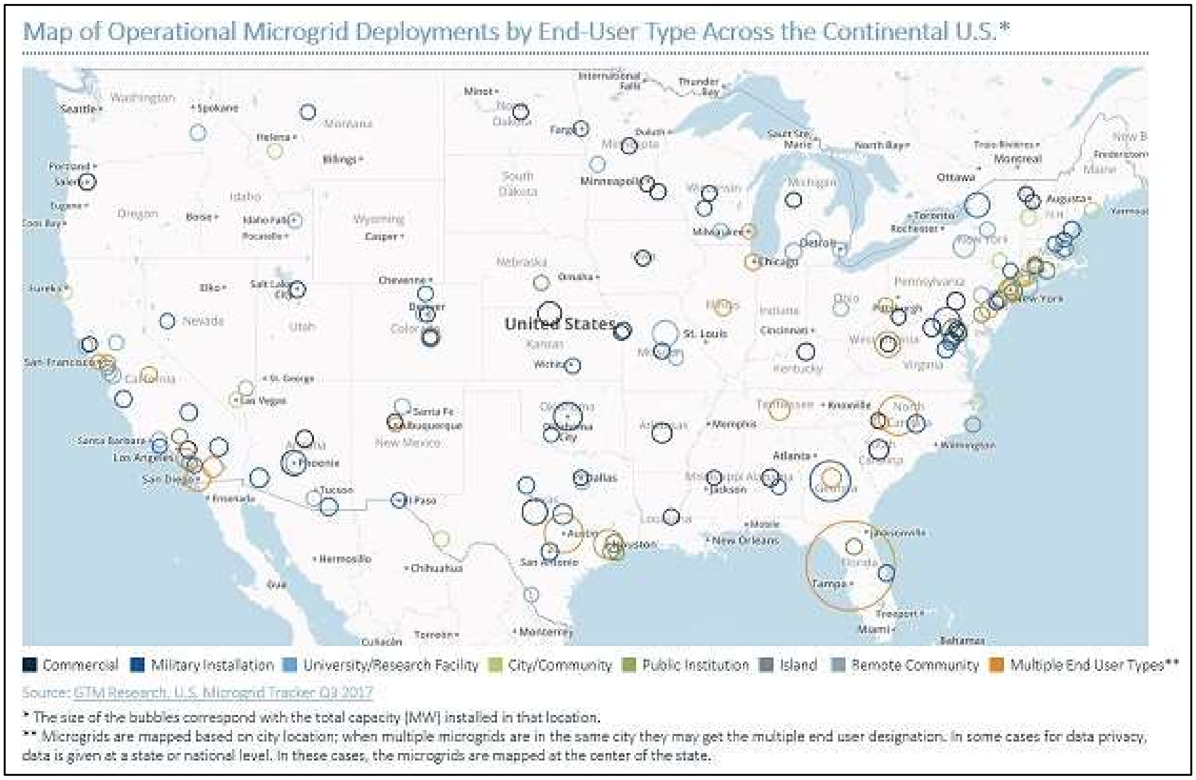
6. Microgrids

Microgrids represent an innovative energy solution whereby a large customer and/ or group of customers can deploy a variety of distributed resources in pursuit of a higher level of reliability and resiliency, potentially operating apart from the grid, particularly during grid outages, as well as other potential benefits. Figure 40, below, provides a national map of microgrid deployments.[221] While microgrids tend to be concentrated on the coasts, their deployment is relatively widespread throughout restructured and non-restructured states, including several microgrids in Arizona.

[220] Map adapted from: Myers, Erika H., Surampudy, Medha, Saxena, Anshul, "Utilities and Electric Vehicles – Evolving to Unlock Grid Value" Smart Electric Power Alliance, March 2018, at 8, available here: https://sepapower.org/resource/utilities-electric-vehicles-evolving-unlock-grid-value/. (Data source: Smart Electric Power Alliance, 2017).

[221] Definitions for microgrids vary, for example, depending on whether multiple distributed energy resources are required to meet the definition of a microgrid. Applying a more limiting definition to such a map would show fewer microgrids.

Figure 40: Map of Operational Microgrid Deployments Across U.S.[222]



Microgrids often include energy storage resources, and, as is the case with energy storage, in restructured states, there can be questions about whether microgrids are essentially distribution or transmission resources or generation; if microgrids are designated as generation, utilities face ownership limitations in restructured states.[223] As with other innovations discussed in the chapter, the development of microgrids depends on regulatory and legal factors, including whether policy makers undertake actions to address barriers to microgrid deployment.[224]

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222 Wood, Elisa, Microgrid Knowledge, "New GTM Report Forecasts $12.5B Microgrid Investment within US by 2022" (Nov. 30, 2017), source: GTM Research, "U.S. Microgrids 2017: Market Drivers, Analysis and Forecast".

223 Wood, Elisa, Microgrid Knowledge, "New GTM Report Forecasts $12.5B Microgrid Investment within US by 2022" (Nov. 30, 2017), including citing Colleen Metelitsa, GTM analyst and author of report, "GTM Research, "U.S. Microgrids 2017: Market Drivers, Analysis and Forecast".

224 National Electrical Manufacturers Association, "State Regulatory and Policy Considerations for Increased Microgrid Deployment - A Public Policy Primer" (2018).