Understanding Electricity Markets in Ohio

Andrew R. Thomas  
*Cleveland State University*, a.r.thomas99@csuohio.edu

Iryna Lendel  
*Cleveland State University*, i.lendel@csuohio.edu

Sunjoo Park

How does access to this work benefit you? Let us know!
Follow this and additional works at: [https://engagedscholarship.csuohio.edu/urban_facpub](https://engagedscholarship.csuohio.edu/urban_facpub)

Part of the [Urban Studies and Planning Commons](#)

Repository Citation
[https://engagedscholarship.csuohio.edu/urban_facpub/1268](https://engagedscholarship.csuohio.edu/urban_facpub/1268)

This Report is brought to you for free and open access by the Maxine Goodman Levin College of Urban Affairs at EngagedScholarship@CSU. It has been accepted for inclusion in Urban Publications by an authorized administrator of EngagedScholarship@CSU. For more information, please contact library.es@csuohio.edu.
# Table of Contents

Acknowledgements ........................................................................................................................................... 4

Executive Summary ........................................................................................................................................... 4

I. Introduction ..................................................................................................................................................... 6

II. Background .................................................................................................................................................... 9
   A. Trends for Electricity Prices in Ohio ........................................................................................................... 9
   B. Development of Electricity Markets in Ohio ............................................................................................... 12
      1. Ohio Electricity Markets Prior to Restructuring ..................................................................................... 12
      2. Restructuring of Electricity Markets and Senate Bill 3 ....................................................................... 13
      3. Senate Bill 221 and Revisions to Restructuring .................................................................................. 14
   C. PUCO Investigation into the Status of Ohio’s Electricity Markets ............................................................ 16

III. Understanding Electricity Costs .................................................................................................................. 18
   A. Components of Electricity Costs in Ohio .................................................................................................... 18
   B. Standard Service Offer Option ................................................................................................................... 21
   C. Distribution and Non-By-Passable Charges ............................................................................................... 22
      1. Process for Determining Distributions Rates .......................................................................................... 22
      2. Non-By-Passable Riders ......................................................................................................................... 22
   D. CRES Provider Costs and Wholesale Markets .......................................................................................... 24
      1. RTO Operations in Ohio ......................................................................................................................... 24
      2. PJM Cost Components .......................................................................................................................... 26
         a. Wholesale Energy Prices ...................................................................................................................... 28
         b. Capacity Charges ................................................................................................................................. 30
         c. Transmission Charges ......................................................................................................................... 33
         d. Ancillary Services ................................................................................................................................. 33
   E. Total Electricity Cost in Ohio ..................................................................................................................... 34

IV. Special Problems and Considerations for Electricity Markets in Ohio ......................................................... 36
   A. Energy Market Issues ............................................................................................................................... 36
      1. Locational Marginal Pricing and Electricity Markets ............................................................................ 36
      2. The Problem of New Generation .......................................................................................................... 39
   B. Consumer Purchase Strategies and CRES Provider Products ................................................................. 41
   C. Constraining Capacity Auction Prices ...................................................................................................... 42
   D. Demand Response and Energy Efficiency Programs .............................................................................. 44
      1. Programs in Ohio .................................................................................................................................... 44
      2. Demand Response Programs Available from PJM ............................................................................... 45

V. Conclusions .................................................................................................................................................... 46
List of Figures

Figure 1: Electricity Market Players ......................................................................................................................9
Figure 2: Ohio Retail Electricity Prices: Residential, Commercial and Industrial Customers, 1990-2011 ...........................................................................................................................................10
Figure 3: Average Retail Prices of Industrial Electricity, 1990-2011 (2013 Dollars) ................................................11
Figure 4: Correlation between Natural Gas and Power Prices ..............................................................................12
Figure 5: Ohio Electric Market Restructuring Process ......................................................................................16
Figure 6: Principal Components of Electricity .................................................................................................20
Figure 7: Regional Transmission Organization Map ..........................................................................................25
Figure 8: PJM Service Territory .......................................................................................................................26
Figure 9: Traditional CRES Electricity Cost Components (AEP territory) ............................................................27
Figure 10: Anticipated Makeup of CRES Prices in First Energy Ohio Territory ...................................................28
Figure 11: RPM Cleaning Prices in $/MW-Day .................................................................................................32
Figure 12: RPM Cleaning Prices in $/MWh (60% load factor) ..........................................................................32
Figure 13: PJM Transmission Zones in Capacity Auction ...............................................................................33
Figure 14: Structure of Electricity Retail Prices, 2013 ....................................................................................35
Figure 15: Restructured Electricity Markets ......................................................................................................46

List of Tables

Table 1: Example Components of Electricity Cost – Summer 2013 .................................................................19
Table 2: Example of Shopping Customers Cost Components – Summer 2013 .................................................34
Acknowledgements

The authors would like to gratefully acknowledge the help of Susanne Buckley from Scioto Energy for her helpful suggestions, data and figures. The authors would also like to acknowledge the help of Lisa McAllister from American Public Power for her critical review of the text of this paper and comments thereto, and Cleveland State University graduate students Serena Alexander and Briana Butler for their help with research and figure design.

Executive Summary

Ohio first restructured its electricity markets in 2001. However, only in the last several years has Ohio finally realized the benefits of a competitive electricity market. Electricity prices from Competitive Retail Electricity Service providers have dropped significantly since 2008, in principal part due to the recession, but also in part due to efforts by the Ohio Assembly and the Public Utility Commission of Ohio to make it easier for retail competition to thrive in Ohio.

Restructuring has made it possible for competition for generation. However it has not made understanding electricity markets easy for consumers. Understanding the components that make up the final cost of electricity is fundamental to the consumer’s ability to take advantage of competitive retail markets, and for managing electricity costs. However for those who prefer not to spend resources trying to understand electricity markets, there is available a default option for the purchase of electricity – the Standard Service Offer – pursuant to which the traditional incumbent utilities deliver power under the supervision of the Public Utility Commission of Ohio, as has been done traditionally. The Public Utility Commission of Ohio has recently required that the incumbent utilities use market-based wholesale electricity auctions to establish in part the Standard Service Offer price. Transmission, capacity, distribution and non-bypassable rider costs are added to the auction-based prices, plus a Public Utility Commission approved rate of return.

For those who do want to shop for their electricity supplier, there are a variety of competitive retail electricity service providers who provide a variety of products, ranging from fixed price contracts to variable rate contracts, and contracts that mix the two, called “block and index” pricing. The competitive retail service providers must beat the default price if they expect to win supply contracts. In addition, the competitive retail service providers pass through costs to the consumers from the Regional Transmission Organization that serves Ohio, PJM Interconnect. Regional Transmission Organizations are Federal Energy Regulatory Commission sanctioned organizations created to manage interstate transmission and wholesale electricity markets.

Pass through PJM costs includes capacity and ancillary charges. Historically, each has comprised less than 10% of the total cost of power delivered by the retail provider (in other words, all costs but distribution and non-bypassable rider costs). Ancillary costs, which include operational costs incurred by PJM, endured some surprising spikes during the unusually cold winter of 2014, but remain a small part of the cost of electricity.

However in recent years, capacity charges have risen dramatically, especially in northern Ohio. Capacity charges, which are the costs incurred by PJM in making generation available on standby for peak consumption requirements, are determined regionally within the PJM territory through three-year ahead auctions conducted by PJM. Northern Ohio will have the highest
capacity costs in the PJM territory in 2015, rising to comprise around 30% of the cost of competitive retail price. Imported capacity from the MISO Regional Transmission Organization west of PJM have somewhat mitigated this problem for 2016 and 2017, however high capacity charges remains a significant concern for Ohio consumers. Capacity costs can be managed in part by reducing load during grid peak usage times the summer before the charges are set.

Wholesale energy can be purchased either through bilateral contracts or through spot markets. Most bilateral sales are done through brokerage houses or through hub locations within the Intercontinental Exchange. Spot markets are operated by PJM as either day ahead or real time markets. Locational Marginal Pricing, which is a PJM algorithm that combines elements of generation cost and transmission congestion cost, provides the mechanism for creating the market price. The final bid that clears the required energy sets the price for all energy bid into the market, and is designed to approximate the marginal cost of power production. However concerns that the incumbent utilities may exert too much market power has led PJM to put into place programs to monitor the market.

Distribution and non-by-passable riders form the final portion of the cost of power. These costs are normally billed directly by the local electric distribution utility to the shopping consumer, and are separate from the invoice from the competitive retail provider. The distribution charge is set as a tariff applied for by the electric distribution utility, and approved by the Public Utility Commission. Non-by-passable riders are also charged directly to the consumer by the electric distribution utility, and typically are permitted and approved by the Public Utility Commission or by state law to recover the costs of social programs. Some programs, such as recovery of costs for economic development or demand side energy efficiency programs, have been the source of controversy in Ohio.

In Ohio, energy\(^1\) currently comprises about 50% of the total retail electric bill, with the rest being made up of capacity, ancillary, distribution and non-by-passable riders. As capacity prices increase, energy prices will increasingly comprise less than half the total cost. In the AEP territory, transmission costs are included in the PJM costs passed through to the competitive retail provider, and typically are around 5% of that cost. In other territories in Ohio, transmission costs are billed directly by the electric distribution utility.

For Ohio, constraining electricity costs for manufacturers will require a focus primarily upon shopping for the right commercial retail plan and upon managing the capacity costs. In addition, participation in demand response and energy efficiency programs will likely be important factors in constraining electricity costs. On the policy side, manufacturer advocates will need to monitor potential problems stemming from market power exerted by the incumbent utilities for both the energy and capacity markets. Under current policies, utilities are not incentivized to build new generation in response to high prices, but instead to build new transmission in response to congestion. This may not be the most economical approach for the consumers, however. Often times, the most economical approach for utilities is to maintain congestion, which tends to drive prices higher.

---

\(^1\)“Energy” in this context refers to the actual making of electricity. This is a term of convenience to separate it from the other components of electricity costs, such as capacity, transmission and distribution. Using the word “electricity” to describe the making of electricity has proven to be too confusing, so the industry has developed this terminology.
I. Introduction

Electricity markets in the United States are complex systems that can be difficult for consumers, policy makers and even energy experts to understand. This is especially so for states like Ohio, which have deployed “restructured” electricity markets—the name commonly used to describe the deregulation of the generation side of the sale of electricity. In traditional electricity markets, all aspects of the sale are heavily regulated under the theory that the generation, transmission and distribution of power form a “natural monopoly,” and therefore require government oversight to ensure that there will be no consumer abuse.2

Under the traditional model, state and/or federal agencies regulate the electricity market, and rates are set for the delivery of power to consumers on a “cost plus” basis. Under this model, electricity prices are based upon recovering the costs of generating, transmitting and distributing power, plus a profit that is set as a percentage of these costs. The cost of power is presented to the consumer as a price per kilowatt-hour (kWh) used, the number of which is measured by a meter at the location of consumption. The more power consumed, the higher the electricity bill. In Ohio, traditionally, power has been priced at the same rate by customer class as determined through a regulatory rate case, regardless of the cost of generation, transmission or distribution, and regardless of the time or date of consumption.

For a long time, this system worked reasonably well. Real costs of power steadily decreased in the United States for forty years, as new technology and economies of scale drove down prices. But inevitably the “cost plus” model, which rewarded cost overruns and inefficient operations, began to create problems. By the 1970s, aided by the oil and gas crisis, together with massive cost overruns in nuclear power generation, electricity costs were on a steady rise. The 1978 passage of the Public Utilities Regulatory Policies Act (PURPA) further inflamed the problem by requiring utilities to purchase electricity from “qualified facilities” (new facilities that were either below 80 MW or were not fossil fuel-based) operated by Independent Power Producers, whether the price for such power was market rate.3 The result was a feed in tariff that utilities had to pay that burdened ratepayers with high prices for long periods of time.

By the late-1980s, natural gas prices had collapsed, partly in response to the deregulation of that industry. Of particular interest was FERC Order Number 436, passed in 1985, which required that natural gas transmission companies provide producers “open access” to their pipelines.4 Electricity consumers took note. Led initially by large industrial users, consumers began to ask why electricity generation could not similarly be made competitive. By the 1990s, principally in response to PURPA, the first wholesale power markets began to appear. By the late 1990s the first restructured state electricity markets, most notably in California, were adopted.

Market restructuring introduced the concept of a competitive market for electricity generation, whereby wholesale power generators would compete with each other to sell electricity to distributors for the purpose of resale. It was hoped by policy makers that a free market for the purchase and sale of wholesale power would eliminate some of the cost overruns

---

2 The goal of regulation of natural monopolies like electricity is to simulate, as best as possible under the circumstances, market conditions. See e.g., J. Lesser and L. Giacchino, *Fundamentals of Energy Regulation*, 9-11 (Public Utilities Reports 2007).
4 Order 436 was described as “one of the three great regulatory milestones of the industry” by the reviewing court that upheld the regulation. See e.g. http://www.ingaa.org/cms/1502.aspx
and inefficiencies that had become epidemic under the old “cost plus” recovery mechanisms. Transmission and distribution of electricity remained a natural monopoly, however, and as such continued to be regulated by state and federal agencies.

Creating a truly competitive market for the sale of wholesale power turned out to be more complex than that for natural gas. Unlike for electricity, the natural gas transportation industry has not been historically entangled (“vertically integrated”) with the producing industry. Natural gas transmission and distribution companies that have ventured into the business of exploration and production generally found it to be less profitable, just as have exploration and production companies found transmission and distribution ventures. Electric utilities, on the other hand, had heretofore owned and operated the entire electrical delivery system -- from generation to transmission to distribution – and as a result there was no wholesale market. Utilities, naturally, had little incentive to allow competitors into their territory. Proponents of restructuring understood well that the biggest hurdle to creating open markets would lie in untangling the vertical integration of the electric utility industry, and in determining which aspects of the electricity market would be compatible with the concepts of deregulation.

In 1996 the Federal Energy Regulatory Commission, having determined that it was in the public’s interest to create an active wholesale power market, promulgated nondiscriminatory open access rules for electricity transmission (FERC Order 888), similar to that found for the natural gas pipeline industry. Under this order, utilities were required to provide access to transmission lines for wholesale electricity providers under the same terms and conditions that the utilities provided transmission capacity to its own affiliated generation company. FERC additionally required that utilities together create a new organization called the “Independent System Operator” (ISO), which would be tasked with the operation of the electricity transmission grid. The ISO, as structured by the FERC, could dispatch power but had no financial interest in either the sales or the electricity markets, and no ownership interest in the assets used to generate or transmit electricity. Instead, the RTO charged a management fee for their services.

Experience, however, soon taught regulators that an open access rule would not, itself, make it possible for wholesale power to be moved from territory to territory, especially where grid constraint was a problem. Incumbent utilities found ways to frustrate access to their transmission lines and to keep out competition in the wholesale electricity markets – what FERC identified as “residual discrimination.”

This led to FERC Order 2000 in 1999 and the development of “regional transmission organizations (RTOs)” – the new name given for ISOs. FERC Order 2000 detailed the obligations of the RTO, and tasked them with developing best practices for wholesale market design. The RTOs were set up, among other duties, to administer energy service markets, ancillary markets, capacity markets, financial transmission rights, and uniform transmission tariffs. Deregulated markets that did not join an RTO were required to engage an independent entity to administer their system.

---

5 One reason why the natural gas industry has not historically been vertically integrated is that natural gas exploration, unlike for the generation of electrons, has been (at least until the advent of shale development) a high risk, high reward business. Accordingly, natural gas transmission requires a very different business model than that required for exploration.


The result was the creation of a new set of complex rules governing an assortment of charges on all aspects of transmission and wholesale electricity markets. Investor owned utilities that engaged in the generation, transmission and distribution of power within a state continued to be regulated wholly by the state utility commission. However, power generated and transmitted interstate – which is what restructured markets require -- would be subject to management by a regional transmission organization, and regulated by the FERC. Meanwhile, distribution in these states remained an intrastate activity, and was therefore subject to state regulation. Accordingly, electricity sales in restructured states could now have regulatory oversight from either state or federal agencies. This dual regulation added complexity to understanding electricity markets in states that restructured.

It is important to note that not all states have restructured their electricity markets. Not surprisingly, the states that have undergone restructuring have tended to be those states that have endured higher costs for power, such as Ohio and Pennsylvania. Other states, such as Kentucky, which has access to cheap coal, never have restructured. It is also important to note that some 10 plus years into the restructuring experiment, it is still not entirely clear how successful restructuring has been or will be in constraining price increases in electricity.

This paper is not intended to be an analysis of which market structures do or do not work well, but rather to be a guide to a general understanding of how electricity markets work in Ohio. In addition, it is intended to be a review of relevant literature that has been written to date about post-restructured electricity markets, how they work, and what problems have been identified – especially as they relate to Ohio.
II. Background

A. Trends for Electricity Prices in Ohio

Ohio is one of the nation’s top electricity generators and also a major consumer/importer of electricity. As of 2010, the state of Ohio ranked seventh in net electricity generation (143,598,337 MWh), yet at the same time it ranked fourth in total retail sales (154,145,418 MWh) (EIA, 2012).8

The average total blended retail price of electricity in Ohio, including residential, industrial, commercial, and transportation electricity, was 9.14 cents per kWh in 2010 (23rd highest among the states). That same year, the average retail price of industrial electricity in

---

Ohio was 6.40 cents/kWh (26th), below the 2010 U.S. average of 6.77 cents/kWh. Retail prices of industrial electricity in Ohio increased continually from 1990 through 2009, except 2001. However, since 2009, Ohio has experienced a significant decrease in the retail price of industrial electricity from 6.71 in 2009 to 6.12 cents/kWh in 2011.9 During this same time period, the retail prices of residential and commercial electricity in Ohio continued to increase. Meanwhile, the U.S. average retail price of industrial electricity remained at the same rate -- about 6.80 cents/kWh.

**Figure 2: Ohio Retail Electricity Prices: Residential, Commercial and Industrial Customers, 1990-2011**

![Graph showing electricity prices](image)

Source: U.S. Energy Information Administration (EIA-861)
Note: Values are not adjusted for inflation.

Figure 3 shows the electricity retail prices for industrial customer power in Ohio, four adjacent states, and the national average from 1990 through 2011, in nominal dollars. The black dotted line, the trend of national average retail price of industrial electricity over the past two decades, shows that retail electricity prices decreased modestly between 1993 and 1999, rose steadily thereafter until 2008, and then leveled out at around 6.8 cents/kW-hr. But the U.S. average industrial price for electricity rose from 4.74 cents/kWh in 1990 to 6.82 cents/kWh in 2011 in 2013 dollars – an increase of some 44%. This national trend provided motivation for restructuring among the states.

Ohio’s electricity retail price for industrial customers did not enjoy the downward trend that was enjoyed nationally during the 1990s. It started out lower, but by the late 1990s Ohio’s prices had caught up with the national average. Thereafter, both Ohio and national prices rose, until 2009, when Ohio’s industrial retail prices declined steeply, while national prices leveled off. It is unclear whether Ohio’s decline was the result of the recession, further deregulation, or

---

9 EIA, October 2012, Average Price by State by Provider, EIA-861.
Regardless, the combination of a competitive market with the recession led to a drop in industrial retail prices in 2009.

Kentucky and Indiana have not yet restructured their electricity markets, while Michigan, Pennsylvania, and Ohio introduced competition to their electricity markets.\(^{10}\) A comparison of average retail prices for industrial customer power between these states shows that both Indiana and Kentucky have maintained industrial prices below those of the restructured states, causing some experts to question the value of restructuring.\(^{11}\) Other commentators, however, have pointed out that these states all had lower prices to begin with, and that but for deregulation, the difference in prices would have been greater.\(^{12}\)

**Figure 3: Average Retail Prices of Industrial Electricity, 1990-2011 (2013 Dollars)**

![Figure 3: Average Retail Prices of Industrial Electricity, 1990-2011 (2013 Dollars)](image)

Source: U.S. Energy Information Administration (EIA-861)
Note: Values are not adjusted for inflation.

In recent years, pricing of electricity nationally has become closely aligned with the cost of natural gas, which is the principal source of fuel for peak generation. This trend is likely to continue, as natural gas is replacing retiring coal plants. With the advent of shale gas development, natural gas prices are projected to stay low for some time, increasing the likelihood that natural gas will continue to be the fuel of choice for both new and peak generation.\(^{13}\) Figure

---


\(^{11}\) See e.g. K. Silverstein, *EnergyBiz*, July 15, 2013 (noting that restructuring may have been “oversold”; but also noting that Indiana may be one of the states now considering restructuring). See: [http://www.energybiz.com/article/13/07/electricity-market-restructuring-undergoing-revival](http://www.energybiz.com/article/13/07/electricity-market-restructuring-undergoing-revival)

\(^{12}\) See, e.g. “Consumers in Peril,” American Public Power Association, at v (“restructured markets are producing higher prices (and higher profits) than one would expect in a competitive market.”) (February 2008), found at: [http://www.citizenpower.com/NEED/citations/Consumers%20in%20Peril.pdf](http://www.citizenpower.com/NEED/citations/Consumers%20in%20Peril.pdf)

3 below demonstrates how closely AEP-Dayton Hub Power prices have tracked Henry Hub natural gas prices in recent years.

**Figure 4: Correlation between Natural Gas and Power Prices**

NYMEX Henry Hub – Calendar 2013 vs. AEP-Dayton Hub Power – Calendar 2013

Source: GDF SUEZ, *The State of Electricity: Ohio*

**B. Development of Electricity Markets in Ohio**

1. Ohio Electricity Markets Prior to Restructuring

Before the passage of Amended Substitute Senate Bill 3 (SB 3)\(^{14}\) in 1999 (and the subsequent enactment of the law in January 2001), Ohio’s electricity utilities were regulated by the Public Utilities Commission of Ohio (PUCO) under the “traditional approach” to regulation: transmission, distribution and generation were “bundled” together in a package by the local utility.\(^{15}\) Under this model, there was a restriction on geographic market, leading to a “certified territory”\(^{16}\) for each utility.\(^{17}\) Accordingly, electric utilities in Ohio provided a bundled package of electricity generation, transmission, and distribution.

---

\(^{14}\) Senate Bill 3 was introduced to Ohio’s 123\(^{rd}\) General Assembly on January 20, 1999, to enact Ohio Revised Code, section 4928.01. Through the Senate and House actions it was substituted and amended several times, and finally passed by General Assembly and signed by Governor on July 6, 1999 as Am. Sub. S.B.3.

\(^{15}\) Ohio Public Utilities Commission Docket, Case No. 12-3151-EL-COI, entry of Commission’s findings setting forth investigation into Ohio’s retail market, at 1 (December 12, 2012); found at: [http://dis.puc.state.oh.us/TiffToPdf/A1001001A12L12B14210G58737.pdf](http://dis.puc.state.oh.us/TiffToPdf/A1001001A12L12B14210G58737.pdf)

\(^{16}\) Ohio Code, Title 49. XLIX Public Utilities, Chapter 4933: Companies – Gas; Electric; Water; Others, 4933.81. Certified territories for electric suppliers definition: [http://codes.ohio.gov/orc/4933](http://codes.ohio.gov/orc/4933).
Prior to 2001, there were eight for-profit public utilities and 26 non-profit electric utilities in Ohio, all of which provided “bundled” retail electric service—electricity generation, transmission, and distribution—to customers within their respective certified territories. About 91 percent of the electric market services in Ohio were provided by the eight for-profit utilities (also called “investor owned utilities,” or “IOUs”).\textsuperscript{18} In particular, four electric distribution utilities (EDU) – AEP Ohio, Dayton Power & Light, Duke Energy, and FirstEnergy – generated and supplied most of the electricity consumed in Ohio.\textsuperscript{19}

Under Ohio electricity regulation the IOUs are required to petition the PUCO for approval of their electric rates. Under the pre-2001 law, electricity rates included the cost of operation reported by the utilities, typically accounting for 80\% of the utilities’ revenue, plus a rate of return on that part of the utilities’ capital investment that was determined to be “used and useful.”\textsuperscript{20} Under this traditional way of determining the electricity rate, consumers bore the risk of the entire cost of operation, from generation to transmission to distribution, so long as those operations were deemed to be “useful” to the process of delivering power to the consumers. However the return on capital investment portion of the electricity rate could only include those investments made into infrastructure currently in use by utilities for electricity generation and delivery.

2. Restructuring of Electricity Markets and Senate Bill 3

Since the late 1990s 24 states, including Ohio, have restructured their electric power markets. The Ohio Electric Restructuring Act (SB 3) in 1999 authorized the 2001 deregulation of the electric power industry to introduce and develop competitive market systems in Ohio.

The restructuring required electric utilities to separate or “unbundle” their services and charges of electricity generation, transmission, and distribution and to allow retail customers to choose their electric retail suppliers.\textsuperscript{21} Under SB 3, competitive retail services included electric generation, aggregation, and power marketing and brokering. Additionally, metering, billing, and collection services may be performed as part of competitive retail services. However, SB 3 ensured that IOUs retained a monopoly status for electric transmission and distribution services, which services continued to be regulated by the PUCO under a “cost plus” regulatory scheme.\textsuperscript{22}

SB 3 enabled electricity customers to have the choice, beginning on January 1, 2001, of competitive retail service providers. It established a “Market Development Period” through December 31, 2005 to enable the transition to a competitive retail market. During this period, then current electric rates were frozen pending the development of a competitive wholesale market. During 2004 and 2005, FirstEnergy (Ohio Edison Company, The Cleveland Electric

\textsuperscript{17} Ohio Legislative Service Commission, Final Analysis, Am. Sub. S.B. 3 (Ohio Legislative Service Commission, 1999).
\textsuperscript{18} Ohio Legislative Service Commission, 1999.
\textsuperscript{19} T. Snitchler, “The Emerging Ohio Market,” presented at 21\textsuperscript{st} Century Manufacturing Task Force (November 26, 2012). “IOUs” and “EDUs” are often used interchangeably, but the restructuring of the electricity markets brought about a more clear distinction. EDUs are generally in the business of electricity distribution, while the IOUs are in the business of electricity more generally.
\textsuperscript{21} Ohio Public Utilities Commission Docket, Case No. 12-3151-EL-COI, supra, at 1.
\textsuperscript{22} Ohio Legislative Service Commission, supra. For instance, PUCO approved a 9.46\% rate of return for Duke Energy on November 22, 2010 (p.41, PUCO, 2013). For each of FirstEnergy’s operating companies, PUCO approved an 8.48\% return rate.
The Illuminating Company, and The Toledo Edison Company) conducted wholesale electric competitive bidding processes to develop the cost of electricity. However, the fully competitive electricity market envisioned by the writers of SB 3 did not emerge by the end of the market development period, as no competitive retail electric service (CRES) providers were bidding on loads, or were otherwise uncompetitive when they did.  

As a result, the PUCO, together with Ohio’s electric utilities, established plans to minimize market uncertainty and to provide customers a gradual transition to market-based rates with stable and predictable rates. This “Rate Stabilization Period” took place for FirstEnergy, Duke Energy Ohio, Dayton Power and Light, and American Electric Power from 2006 through 2008. Examples of utility specific Rate Stabilization Plans (RSPs) include:

- Dayton Power and Light – Five-year RSP, 2006-2010: an 11% capped increase of generation rate over 5 years; froze distribution rates through 2008; PUCO could terminate the RSP if market prices fall.
- American Electric Power – Three-year RSP, 2006-2008: a 3% increase in generation rate for each year for Columbus Southern Power customers and by 7% for Ohio Power customers; froze distribution rates through 2008.

3. Senate Bill 221 and Revisions to Restructuring

When the utilities’ rate stabilization plans under SB 3 were nearing expiration, then-Governor Ted Strickland announced a new energy plan, entitled “Energy, Jobs, and Progress Plan,” in August 2007. The Governor’s energy proposal included four major goals: (1) stable and predictable electricity rates, (2) the development of advanced and renewable energy technologies, (3) an increase of energy efficiency, and (4) the modernization of electric infrastructure.

Ohio passed Amended Substitute Senate Bill 221 (SB 221) in May 2008 largely incorporating the Governor’s proposal. The plan was most notable for its enactment of a renewable energy portfolio for Ohio, as well energy efficiency mandates. However the plan also revisited and revised the Ohio’s strategies for restructuring electricity markets.

SB 221 changed the regulatory framework that applies to EDUs. SB 3 defined an EDU as “an electric light company that has a certified territory and is engaged on a for-profit basis either in the business of supplying noncompetitive retail electric service in this state or in the business of supplying both a noncompetitive and a competitive retail electric services in this

---

24 Id.
state” (thereby excluding municipal utilities).26 SB 221 further defined an EDU as “an electric utility that supplies at least retail electric distribution service.”27

SB 221 required Ohio’s electric utilities to implement a “hybrid approach” to setting electric rates for default service (i.e., the price for those customers who do not actively choose an alternative retail supplier).28 Instead of fully relying on the competitive market approach to establish the price for this default service, SB 221 requires each of Ohio’s EDUs to develop a standard service offer (SSO),29 defined as “an offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service, and be offered on a comparable and nondiscriminatory basis.”30

The SSO, under SB 221, must be either an electric security plan (ESP)31 or a market rate offer (MRO).32 The ESP is a traditional rate plan based on a cost-of-service proposal from the EDU (which can include both generated and purchased power); while the MRO is a market-based pricing system that sets retail rates through a competitive bidding process pursuant to which the EDU seeks bids from wholesale suppliers of power. To stabilize electricity prices, SB 221 authorized the PUCO to establish rules and to test utilities’ SSO proposals to determine whether they were “fair and equitable” to consumers, and to determine if EDUs would generate excessive earnings from the rates.

While SB 221 preserved SB 3’s requirement that the SSO be the default service for its customers, the bill amended the PUCO’s approval process and enabled the EDUs to choose either the ESP or the MRO. To date, only ESPs have been filed with the PUCO by Ohio EDUs; however the ESPs have included aspects of the market rate option by using supply auctions to establish the cost of delivering power under the SSO.

Pursuant to SB 221, the PUCO furthered the deregulation process by requiring corporate separation of non-competitive retail electric service from competitive electric service.33 Notwithstanding this, as of January 2014, three of the four IOUs in Ohio electric remained vertically integrated, meaning that these incumbent utilities had not yet organizationally separated their generation from their transmission and distribution systems. However all the utilities have taken steps toward separation.34

In addition to the EDUs, another important electricity market player in Ohio is the “Competitive Retail Electric Service” (CRES) provider. Attracting competitive retail electricity providers to bid on loads in Ohio was critical to the success of the market restructuring. The PUCO recognizes two types of competitive retail providers: (1) competitive retail electric suppliers, and (2) government aggregators. As of March 2014, there were 664 competitive retail electric providers in Ohio, of which 255 were government aggregators, and 409 were

27 Id.
29 The term “Standard Service Offer” is also called the “Provider of Last Resort” offer – in other words the default service when the consumer fails to choose a provider. EPSA Electricity Primer at 4. www.esps.org.
32 Ohio Rev. Code Section 4928.142.
33 PUCO Case Number 12-3151-EL-COI, Entry Order from PUCO, dated 12/12/2012 at 1.
competitive retail electric suppliers (CRES) providers. The PUCO recognized multiple forms of CRES providers, including brokers/nongovernment aggregators (277), generators (36), and marketers (96). Many CRES providers list themselves in multiple categories, making it appear that there are more registered CRES providers than there actually are.

**Figure 5: Ohio Electric Market Restructuring Process**

![Diagram of Ohio Electric Market Restructuring Process]

Source: Authors

**C. PUCO Investigation into the Status of Ohio’s Electricity Markets**

In December of 2012, the PUCO initiated an investigation into the state of Ohio’s retail market, in an effort to “determine where the market is working, [where it is] in need of improvement, and how the retail market could be improved for the benefit of consumers.” According to then-PUCO Chairman Todd A. Snitchler, the study was “the next logical step in the transition from a regulated environment to a restructured market.” The PUCO set up case number 12-3151-EL-COI (“Electricity Market Docket”) and invited comments on a series of questions from all parties with a stake in electricity markets. In addition, the PUCO scheduled a series of six workshops for purpose of exploring ways to improve the retail market for electricity in Ohio.

Responders included such organizations as wholesale and retail power suppliers, distribution utilities, large-scale industrial users, aggregators, environmental advocates and

---


37 Id.
consumer and citizen group advocates. The commentary submitted into this docket provides insight into understanding Ohio’s markets.

The questions asked by the PUCO include, among others, (1) whether the existing retail electric service market design presents barriers to a “fully functional competitive retail electric service market;” (2) whether the current default service model impedes competition; (3) whether Ohio should continue the “hybrid model” that includes both an “electricity stability plan” and a “market rate option;” and (4) what legislative or commission changes can be implemented that might improve the competitive nature of retail markets in Ohio.38

On January 16, 2014 the PUCO staff submitted its “findings and recommendations” after having reviewed over 100 documents filed in the docket and after having participated in the six workshops. The PUCO reserved the right to disagree with the findings of its staff.39 The PUCO further requested that comments to the findings be submitted to docket by February 2, 2014.40

The first item the PUCO staff addressed was to define what “effective competition” meant in the current Ohio retail electric market. It concluded that effective competition would be defined by: (1) participation in the market by multiple sellers such that one individual seller did not significantly influence the market; (2) participation in the retail market by informed buyers; (3) no substantial barriers to suppliers entering the market; (4) no substantial barriers to customers from participating in the retail market, and (5) sellers offering buyers a variety of competitive retail services.41

The definition of “effective competition” is important to the PUCO because it recognized that true market competition is unattainable in a partially deregulated electricity market. The goal for the PUCO, then, is to “attain a level of competition that creates and encourages benefits for both buyers and sellers.”42 To achieve these goals, the PUCO staff recommended that all EDUs in Ohio be structurally separated from their retail sales arm, that 100% of the SSO load be procured through a competitive process for all EDUs in Ohio, and that customers be engaged and informed about the products and services that are available.43

Notwithstanding the recommendation that generation be structurally separated from distribution, the PUCO staff felt that it was sufficient to have “functional separation” to meet the goals of corporate separation. This, the staff believed, could be accomplished through “structural separation with an affiliate.” Accordingly, it recommended “no further action” with regard to the utilities fully divesting their generation and supply functions from their distribution and transmission functions.44 Under the current ordered separation timeline, for the Ohio EDUs will be structurally separated as follows: AEP Ohio in January 2014; Duke Energy Ohio by December 31, 2014; and, Dayton Power & Light by May 31, 2017. First Energy already achieved structural separation in 2009.45

38 PUCO Case Number 12-3151-EL-COI, Entry Order from PUCO, dated 12/12/2012.
39 Id., Entry Number 127, dated 1/16/2014.
40 Id., Entry Number 128, dated 1/16/2014.
41 Id., Entry Number 127 at 9.
42 Id.
43 Id. at 10.
44 Id. at 12.
45 Id. at 13. Note that EDU separation from the retail arm is different from EDU separation from the generation asset owning part of the company. For example, AEP has AEP Retail and AEP Gen Co and AEP Ohio. In its reply, Duke Energy Ohio noted that it no longer operates a supplier function in Ohio. It further notes that it anticipates its generation assets will be divested by December 31, 2014. See Comments of Duke Energy Ohio, Inc., at 4 (February 6, 2014), found at: http://dis.puc.state.oh.us/TiffToPDf/A1001001A14B06B62026D42752.pdf
Another issue that was addressed was the standardization of EDU invoices. Utilities opposed standardization because it would impose costly billing format development for Ohio companies that may be different from multi-state billing formats. The PUCO staff recommended that utilities adopt similar “price to compare” protocols, and adopt consistent definitions for terms such as “supply” and “delivery.” The staff also recommended that Ohio’s EDU invoicing and other processes could be standardized across the state by working collaboratively with other states within the PJM region.

A number of stakeholders to the proceeding offered recommendations on how the PUCO could eliminate barriers to a “fully functional competitive retail electric service market.” However the PUCO chose to not address these recommendations in its final report.

III. Understanding Electricity Costs

A. Components of Electricity Costs in Ohio

With market restructuring, the consumer now has more complex components to their electricity invoices. The following discussion breaks down the various cost components of electricity, along with an analysis of how these charges are arrived at and what control, if any, the customer has over these costs (Table 1).

The following chart sets forth typical cost scenarios for an industrial electricity user in Ohio, broken down into component parts. The Standard Service Offer for generation is considered as “by-passable,” meaning that the end user can elect to not take that service, but instead seek service in another manner. The alternative to taking the SSO generation is to acquire power from a CRES provider or an aggregator.

46 Id. at 20.
47 Id. at 25.
48 See e.g. “Comments of the Industrial Energy Users-Ohio, at 3 (February 6, 2014). Found at: http://dis.puc.state.oh.us/TiffToPDf/A1001001A14B06B63007C58587.pdf
### Table 1: Example Components of Electricity Cost – Summer 2013

<table>
<thead>
<tr>
<th>Service Product</th>
<th>By-Passable Standard offer Service Generation</th>
<th>By-Passable Utility Charged Capacity</th>
<th>By-Passable Riders</th>
<th>By-Passable Transmission</th>
<th>Non-by passable Riders</th>
<th>Distribution</th>
<th>Energy</th>
<th>Capacity</th>
<th>Ancillary Services</th>
<th>Losses and Other</th>
<th>Total Rate Under Utility Supply</th>
<th>Total Rate Under CRES Supply</th>
<th>Shopping Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>By-Passable Standard offer Service Generation</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.1103</td>
<td>$0.0812</td>
<td>$0.0291</td>
</tr>
<tr>
<td>Non-by passable Riders</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.1130</td>
<td>$0.0909</td>
<td>$0.0221</td>
</tr>
<tr>
<td>Distribution</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.0869</td>
<td>$0.0757</td>
<td>$0.0112</td>
</tr>
<tr>
<td>Energy</td>
<td>up to 1.0 Hrs Cap, 0.9 Hrs Load Factor</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.0945</td>
<td>$0.0828</td>
<td>$0.0117</td>
</tr>
<tr>
<td>Transmission</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.1142</td>
<td>$0.1014</td>
<td>$0.0127</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.1072</td>
<td>$0.0954</td>
<td>$0.0117</td>
</tr>
<tr>
<td>Losses and Other</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.1137</td>
<td>$0.1012</td>
<td>$0.0125</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SHOPPING CUSTOMERS COST COMPONENTS</th>
<th>AEP CS</th>
<th>AEP OP</th>
<th>DPL</th>
<th>Duke</th>
<th>FE - TE</th>
<th>FE - OE</th>
<th>FE - CEI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Passable Utility Charges</td>
<td>19%</td>
<td>28%</td>
<td>17%</td>
<td>19%</td>
<td>27%</td>
<td>29%</td>
<td>27%</td>
</tr>
<tr>
<td>Distribution</td>
<td>14%</td>
<td>12%</td>
<td>15%</td>
<td>18%</td>
<td>22%</td>
<td>16%</td>
<td>21%</td>
</tr>
<tr>
<td>Transmission</td>
<td>9%</td>
<td>8%</td>
<td>5%</td>
<td>5%</td>
<td>4%</td>
<td>4%</td>
<td>4%</td>
</tr>
<tr>
<td>Energy</td>
<td>51%</td>
<td>45%</td>
<td>54%</td>
<td>50%</td>
<td>41%</td>
<td>44%</td>
<td>41%</td>
</tr>
<tr>
<td>Capacity</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>Ancillary Svs</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>2%</td>
<td>3%</td>
<td>2%</td>
</tr>
<tr>
<td>Losses and Other</td>
<td>2%</td>
<td>2%</td>
<td>3%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
</tr>
</tbody>
</table>

**Min** | **Max** | **Ave**

| Charged by Utility (EDU) only if NOT SHOPPING | | |
| Charged by Utility (EDU) | | |
| Charged by CRES only if SHOPPING | | |

Source: Scioto Energy (based upon typical 50% load factor for a medium sized manufacturing customer, as obtained from CRES providers in the summer of 2013. Load factor is the kW-hrs used in a month/peak usage (kW) times the number of hours in a month. Load factor affects capacity charges in all territories, and transmission charges in the AEP territory.)
In addition to the SSO generation costs, the other by-passable charges include “utility charged capacity,” certain riders, and in the AEP territory, transmission fees. These costs are not avoided, but rather passed through as part of the CRES invoice. Riders, which are additional charges authorized by the PUCO (often to support some social program), are also commonly non-by-passable, and assessed with the EDU distribution bill. An example of this is the rider used by utilities to recover the costs of compliance with energy efficiency mandates.

Distribution costs, which are paid to the EDU, are non-by-passable, and the cost is set by a PUCO approved tariff. Transmission, energy, capacity and ancillary services are all costs that are no longer PUCO jurisdictional. For shopping customers these costs will be typically charged by the CRES provider, although among these, the CRES provider may have control only over the energy costs. The rest of the costs will be pass-through charges from transmission owners or from the regional transmission organization. Finally, line losses will also be part of the CRES provider charge, but will be subsumed within another category, typically energy costs.

Figure 6: Principal Components of Electricity

![Diagram of Principal Components of Electricity]

Source: Authors
B. Standard Service Offer Option

In Ohio, if the electricity consumer does not actively select either a CRES provider or an aggregator, he will be supplied under the utility Standard Service Offer option, otherwise known as “default service” or “service of last resort.” Under the Ohio rules for default service, utilities can choose to provide the service through either an “electric stability plan” or through a “market rate option.” The latter allows for the utility to open up the default service entirely to market conditions. The former allows the utility to recover its costs of generating and/or purchasing power, plus a PUCO approved profit. To date, all Ohio utilities have applied for the ESP option. The ESP option is not without market components; the PUCO has required that the utilities use market-based auctions to establish the default price. However, regardless of the pricing mechanism, incumbent EDUs ultimately have the obligation to serve retail customers who don’t elect another supplier.

The ESP should provide for the supply and pricing of electricity generation. The EDU may establish an SSO price for retail generation that includes recovery of the prudently incurred costs for fuel, purchased power, capacity and emissions, among other costs. The EDU may also purchase power from an affiliate.49

AEP’s first post-electric stability period ESP was approved in March 2009. It set price increases for the base price of electricity generation through December 2011, ranging from 6 to 8 percent.50 From 2011-12, several ESP agreements were implemented, revoked or modified, until finally agreeing upon a structure that transitions the ESP to being market based by 2015.51

FirstEnergy’s current ESP was put into effect in 2011, and freezes FirstEnergy’s distribution rates through May 2014. It also provided some additional items, such as providing support for low-income families, acquisition of renewable energy credits, and economic development investment into its territory.52 Duke’s ESP was put into place in 2012, and runs through May 2015. Under its ESP, Duke will transfer all its assets to an affiliate, and hold five separate auctions to determine generation rates. The ESP also includes economic development and energy efficiency obligations, as well as low-income support.53

In the Electricity Market Docket before the PUCO, consumers and other electricity market stakeholders were asked whether the standard service offer used in Ohio was inhibiting retail competition in Ohio. Currently in Ohio, the majority of electricity consumers are supplied under the SSO default option rather than electing an alternate CRES provider. Not surprisingly, the answer to this question depended upon the perspective of the respondent. The National Energy Marketers Association (NEMA), representing, among others, many CRES providers, argued that it does. NEMA argued that the default service provides an unfair competitive advantage to the incumbent utility, noting that not only does the utility incur no costs in

51 Id.
marketing, but it also enjoys the advantage of a ready market from “consumer apathy” whereby consumers fall into the utility market without making an affirmative decision.54

Others took a different view. The consumer advocates, for instance, argued that the reliance upon the SSO was not just a matter of inertia, but rather a purposeful decision based upon an understanding that the SSO was the product of either regulatory oversight, a wholesale market auction, or both. Under this theory, the SSO sets the bar for a fair price for consumers—a price that CRES providers must beat to be competitive.55 Ultimately, the PUCO staff dismissed the idea that the SSO load should be delegated to the CRES providers in some fashion, insofar as it would create customer confusion. Further, the staff concluded that the default service would be increasingly served through a competitive auction, thereby protecting the consumers.56

C. Distribution and Non-By-Passable Charges

1. Process for Determining Distributions Rates

Whether the electricity is acquired from the incumbent IOU through the Standard Service Offer, or through a CRES provider, distribution charges will also be assessed by the local EDU (i.e., they are non-by-passable). Distribution charges are determined by a PUCO approved tariff. Tariffs are approved for utilities through a formal proceeding called a “rate case,” during which the PUCO determines the reasonableness of the rate request. Interested parties may intervene into the proceedings, and make known their positions in response to the utility’s request.

The utility will request from PUCO the amount it believes is necessary for it to cover its financial obligations of delivering safe and reliable power to all customers, including a rate of return. The PUCO will seek to set a rate that allows the utility to recover its “prudently incurred” expenses for operating and maintaining the distribution grid, plus a “fair” rate of return on the utility’s investments into assets that are “used and useful” in providing distribution service.57 The rates are calculated based upon a 12-month period believed to be representative of the operating conditions for when the rates will apply.58 Other fees are charged over and above the base rate, such as a “customer charge” for handling the administrative costs and state taxes.

2. Non-By-Passable Riders

Utilities may also recover costs through a process known as “single issue ratemaking,” which involves singling out special expenditures from a utility’s expenditures and allowing the

55 Id., “Comments by the Office of the Ohio Consumers’ Counsel,” March 1, 2013 at 7-9 found at: http://dis.puc.state.oh.us/TiffToPDF/A1001001A13C01B65251J17366.pdf
56 Id., “Results of Staff’s Investigation Conducted in Accordance with the Commission Entries,” January 16, 2014, at 14-15, found at: http://dis.puc.state.oh.us/TiffToPDF/A1001001A14A16A95144H29544.pdf. In addition, the CRES providers now have the opportunity to participate in the SSO auctions.
57 Larkin & Associates, “Increasing Use of Surcharges on Consumer utility Bills,” at 1, May 2012 (prepared for the AARP); http://www.aarp.org/content/dam/aarp/aarp_foundation/2012-06/increasing-use-of-surcharges-on-consumer-utility-bills-aarp.pdf
58 Id.
utility to recover these separately through a special surcharge. Historically, regulators had approved surcharges in response to limited circumstances, such as to recover costs that utilities had incurred that were beyond that utility’s control.\textsuperscript{59}

In recent years, however, other types of surcharges – also known as “riders” -- have been passed through to consumers, either through special rate cases or through legislative fiat. Some surcharges seem to be entirely operational, such as environmental compliance, and it is unclear why a separate rider is needed. Others, such as those instituted to pay for programs to support energy efficiency, are not within the ordinary operations of the utility. Ohio has riders for utilities to recover the costs of aging infrastructure, energy efficiency, environmental compliance, renewable energy, smart metering, storm damage, system reliability, vegetation management, transmission investment, uncollectable debts, and universal service/low income support.\textsuperscript{60}

Many of these appear, on their face, to be part of the traditional operating cost of the utility. For this reason, experts have questioned whether the trend for imbedding riders into the distribution charge has the effect of allowing utilities to recover costs that may be in excess of what was determined to be “fair and reasonable.” By guaranteeing full recovery of specific expenses outside of the normal ratemaking process, utilities lose their incentive to reduce costs.\textsuperscript{61}

Moreover, the regulatory agency typically does not exert the same level of oversight for surcharges as it does for rate making, and often times the utility over collects for its costs, requiring some sort of recovery action by the PUCO.\textsuperscript{62}

Charges passed through by the EDU to the customer regardless of who the generation provider is are referred to as “non-by-passable charges.” These include such riders as the Universal Service Fund, which covers low-income customer assistance, and demand side management riders.

Currently the most controversial charge is the DSE2 rider. FirstEnergy argues that it will cost the ratepayers significantly, while others argue it will save ratepayers billions of dollars.\textsuperscript{63} As set forth in that legislation, most energy efficiency work is done behind the meter, which has the net effect of reducing the volume of EDU sales. The demand side management riders permit EDUs to recover the loss of sales and are set by dividing the total operational costs by the total sales. If sales are down, then the rider increases accordingly. Nevertheless, the utilities have generally opposed the energy efficiency portfolio mandate, with efforts to overturn or reduce the mandate.\textsuperscript{64} Utility efforts to overturn or modify renewable portfolio requirements and the energy

\textsuperscript{59} Id. a 1-2.
\textsuperscript{60} Id. at 7-8.
\textsuperscript{61} Id. at 9.
\textsuperscript{62} Id. at 9-10.
\textsuperscript{64} T. Knox, “Seitz expects ‘devastating testimony’ to bolder effort to roll back alternative energy mandates,” Columbus Business First, February 18, 2014, found at: http://www.bizjournals.com/columbus/news/2014/02/18/seitz-expecting-devastating.html?page=all Reduction in demand of course also puts pressure on the market value of electricity generation and capacity costs, and reduces transmission congestion – all which works to reduce the price of electricity. These are additional reasons utilities generally do not support state-sponsored energy efficiency programs.
efficiency mandates of SB 221 were finally rewarded with the passage of SB 310 in June of 2014, when Governor Kasich signed into law a two year freeze on the mandates.\textsuperscript{65} Another controversial rider assessed by the PUCO is the economic development rider. In Ohio, the PUCO has the ability to approve riders that subsidize economic development projects.\textsuperscript{66} Economic development riders are constrained to the EDU region in which the customer who is receiving the subsidy resides. However in October 2013, Ohio lawmakers, through proposed H.B. 312, introduced a bill that seeks to spread the cost of subsidies for these economic development riders across ratepayers statewide, through January 2018.\textsuperscript{67} To date, the bill has not passed.

The most controversial PUCO economic development rider in recent years was that imposed in the AEP territory for the purpose of helping Ormet, an aluminum company in Southeast Ohio, to maintain its operations. Despite more than $150 million in subsidies that were passed through to other AEP customers since 2009, Ormet requested additional support in 2012.\textsuperscript{68} Ormet eventually closed its doors in October 2013, laying off over a thousand workers, leading to protests by former Ormet workers over what they claimed was inaction by the PUCO and AEP in providing economic development support through the rider.\textsuperscript{69}

\section*{D. CRES Provider Costs and Wholesale Markets}

\subsection*{1. RTO Operations in Ohio}

Wholesale markets for electricity, i.e. sales of power for purposes of resale, are open to anyone who can generate power (with the necessary permits), connect to the grid and find a willing buyer. These include competitive utility suppliers (such as First Energy Solutions), independent power producers (IPPs) unaffiliated with a utility, vertically integrated utilities in regulated states, municipal utilities and cooperatives who retain the obligation to serve, and producers of excess distributed (on-site) generation. Moreover to participate in the wholesale market, one need not be a generator. Power trading companies can buy and sell power on the open market just like a generator.\textsuperscript{70}

Wholesale markets are, for the most part, interstate, and as such, are regulated by the Federal Energy Regulatory Commission. For purposes of enabling interstate competition for wholesale electricity, the FERC set up Regional Transmission Organizations (RTOs) to manage the wholesale market and the transmission of power.

Ohio’s RTO is Pennsylvania, Jersey and Maryland Interconnect, known simply as “PJM.” It serves the largest population of any system administrator in America, covering much

\textsuperscript{65} See http://www.legislature.state.oh.us/bills.cfm?ID=130_SB_310.
\textsuperscript{66} Ohio Rev. Code Section 4901:1-38-03 “Economic Development Arrangements.” These programs to subsidize electricity costs have become known as “special arrangements.”
\textsuperscript{67} L. Grengo, \textit{Ohio Legislative Service Commission}, Bill Analysis (October 2013); http://www.lsc.state.oh.us/analyses130/h0312-i-130.pdf
\textsuperscript{70} EPSA Electricity Primer (March 2014), found at: https://www.epsa.org/industry/primer.
of Northeastern United States. North America currently has ten regional electric power markets, seven of which operate in the United States as either Independent System Operators or RTOs.

**Figure 7: Regional Transmission Organization Map**


PJM coordinates and manages both a high-voltage grid (i.e., transmission) and a wholesale electricity market in all or parts of 13 states. States covered by PJM are all or most of Delaware, D.C., Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia, and parts of Illinois, Indiana, Kentucky, Michigan, North Carolina, and Tennessee.\(^1\) PJM’s territory covers an area of 214,000 square miles and a population of over 60 million, with a peak demand

---

of around 164,000 MW. The size of the load managed makes PJM the largest independent system operator in the world.

Figure 8: PJM Service Territory

Source: PJM (http://www.pjm.com/about-pjm/who-we-are/territory-served.aspx)

2. PJM Cost Components

When a CRES provider in the PJM footprint sells power on the retail market, the electricity cost has several components. The most important component is the cost of the energy, which refers to the actual power itself. The energy cost is usually the largest portion of the total cost, and is determined by market forces, but most importantly the cost of generation. The other main components include capacity charges and ancillary services. Line losses may also be another component, but these are usually subsumed within another charge, such as the energy cost. In addition, elements of compliance with local renewable portfolio standards may form another component of the total cost.

These general descriptions of the component costs to the CRES provider price are useful because the actual elements of the PJM price are quite complex. According to the “Customer Guide to PJM Billing,” there are nearly 50 different line items that make up the PJM cost, many of which in turn are made up of subcharges. Each line item is described in the Customer Guide, and they include, among other charges, a variety of transmission, scheduling, and

---


capacity reserve charges, as well as a number of more arcane charges such as those for “black start” and “phase angle” services.\(^\text{75}\)

Delivery costs – moving the power from the generator to the meter – are not directly subject to market forces. Transmission (high voltage transportation) costs are set through a tariff by state regulatory bodies and/or passed through by the utilities to the RTO.\(^\text{76}\) Distribution (low voltage transportation) costs are set by state tariffs, are billed by the EDU separately from PJM, and subject to state regulation. However energy costs are not completely independent from transmission costs, because location always figures into setting the value of energy. Ultimately the cost of energy integrates elements of delivery through PJM’s “locational marginal pricing” algorithm, which depends upon location and grid congestion as factors in setting prices.\(^\text{77}\)

In Ohio, depending upon the EDU territory, transmission costs may be passed through to the CRES provider by PJM. However in most cases they will be billed by the local EDU. The territories of First Energy, Dayton Power & Light and Duke follow the latter strategy, while those customers in AEP’s territory pay the transmission fees through PJM. Accordingly, in the AEP territory, the invoice the consumer sees from the CRES provider will include elements of both delivery and energy generation. In the other EDU territories in Ohio, the transmission charges will be reflected in the EDU distribution bill. In all areas, however, transmission congestion affects capacity and locational marginal pricing.

In the AEP territories, energy costs makes up roughly 75% of the PJM electricity cost component. The remaining cost components, making up the other 25%, consist of “capacity costs” (15%), “transmission costs” (5%) and “ancillary services costs” (5%) (Figure 9 below).

**Figure 9: Traditional CRES Electricity Cost Components (AEP territory)**

![Figure 9: Traditional CRES Electricity Cost Components (AEP territory)](image)

Data Source: GDF SUEZ, *The State of Electricity: Ohio*
Note: Percentages are approximate; does not include utility distribution charges or taxes.

\(^{75}\) *Id.*

\(^{76}\) *Braun, supra,* at 7.

\(^{77}\) See section IV below for a discussion of how capacity and locational marginal prices are affected by grid congestion and location.
In the First Energy territory, where direct transmission charges are set forth in the EDU invoice rather than in the CRES invoice, the costs are allocated among only energy, capacity and ancillary charges. Some experts break this down as 73% for the average energy cost, 16% average capacity cost, and 2% for ancillary services. However the percentages of costs from a CRES provider invoice allocated to energy is expected to change considerably in the coming years. This is because the first energy territory will be experiencing rapid increases in capacity charges as the result of three year ahead capacity auctions (see discussion below).

Figure 10: Anticipated Makeup of CRES Prices in First Energy Ohio Territory

Data Source: Scioto Energy. Note: Percentages are approximate, and do not include taxes or distribution charges. Losses are normally subsumed within energy costs in determining CRES retail prices.

These general descriptions of the component costs to the CRES provider price are useful because the actual elements of the PJM price are quite complex. According to the “Customer Guide to PJM Billing,” there are nearly 50 different line items that make up the PJM cost, many of which in turn are made up of subcharges. Each line item is described in the Customer Guide, and they include, among other charges, a variety of transmission, scheduling, and capacity reserve charges, as well as a number of more arcane charges such as those for “black start” and “phase angle” services.

a. Wholesale Energy Prices

Load-serving entities (i.e. suppliers) acquire the vast majority of their power from their own generation or through long-term bilateral contracts. The bilateral contracts – arms’ length deals between a power supplier and a load-serving entity – are conducted at electricity “hubs” (delivery points) within the PJM territory. Much of the trading is done through on-line trading

---

81 Id.
platforms known as “Intercontinental Exchanges,” or “ICEs.” There are more than two-dozen hubs in the major FERC power regions in North America where on-line, over-the-counter (OTC) trades can be made in the electricity supply market. Market participants include utilities plus other energy and financial companies. In Ohio, the relevant hubs are ATSI (First Energy), DP&L, Duke and AEP.

Before a CRES provider can bid on a retail load, it has to identify where within the hub the load is to be delivered. For this, the CRES provider has to estimate the congestion costs. To do this, the CRES provider relies upon the “locational market pricing (LMP)” – a market construct that is run by PJM and designed to identify the cost of delivering the least cost power to constrained locations within the system. The CRES provider can estimate the costs of delivering the power to the location based upon review of the LMP. If the area does not have any significant grid constraint, then the wholesale price of electricity at that location should be about the same as the OTC price on the ICE.

The PJM wholesale bilateral markets for Ohio have strong liquidity, allowing buyers and sellers to transact easily. This includes sales to speculative financial traders. Electricity brokers are often used to provide information on market conditions, as well as to explain both the physical performance and available financial products, such as options. Contracts can be as short as one day or as long as multiple years. This wholesale bilateral market is the backbone to the retail market as it is used to hedge the electricity supply books of CRES providers.

When there is an inadequacy in supply, or if there is an advantage in price, the CRES provider can also purchase energy from the PJM managed wholesale energy markets. In the PJM energy market, electricity is purchased and sold in either “day ahead” or “real time” spot markets. The day-ahead market permits purchases for anticipated shortages. The real time market, on the other hand, is used primarily to correct for unanticipated weather, load or supply variations.

The spot markets operate as “single clearing price” markets. This means that PJM takes all qualifying offers in ascending order, finally stopping when the last incremental offer meets the necessary supply requirements. This final bid establishes the price paid to all sellers who successfully bid into the market – even for those whose bids were lower than the clearing price.

There is FERC oversight of the PJM wholesale market by a “market monitor.” In practice the market monitor alters less than one percent of the energy offers made. PJM also deploys locational marginal pricing to develop the price for electricity in areas where there is transmission congestion. In those instances where congestion prevents lower cost electricity from being delivered to customers in a constrained zone, the customers will pay more than the clearing price in the market because it is difficult to get the cheaper power to those customers. The added price is referred to as a “congestion charge.”

The CRES providers, in order to reduce risk, usually tie their bigger load retail offers closely to the wholesale price of power. This means that bigger retail deals commonly occur in conjunction with a wholesale transaction. This creates the curious circumstance whereby CRES

---

84 Miranda, at 19.
85 Caplan, at 4.
86 Id., at 5. Customers in congested areas can hedge their congestion costs through devices called “Financial Transmission Rights” or “Congestion Revenue Rights.” These can produce revenues to offset the congestions fees. These have limitations in use, however. Id.
providers will hold retail power offers open for only 24 or 48 hours -- even though the contract may be for several years, and may not even begin for many months.

A more detailed description of how energy markets work, including locational marginal pricing, is set forth in Section IV (A) below.

b. Capacity Charges

Capacity represents the need for adequate generating resources sufficient to meet the demand for power for all locations at any given time within the RTO service area. In short, capacity is a form of standby power that the RTO must acquire to ensure it can meet the instantaneous peak demand load from the grid. Capacity charges refer to the charge the RTO makes to recover fixed costs of this pooled installed generating capacity.

During the period of 1999 to 2005, net revenues from sales into the PJM energy market failed to cover the costs of new generation investment. Market price signals and reliability were not synchronized, and as a result, PJM perceived that reliability within the PJM territory might be compromised. PJM felt the need to develop forward price signals that would encourage peak generation development, and also recognize the locational value of capacity.87

In response to this problem, in 2005 PJM developed a method to allocate among end users the cost of the pooled installed capacity. They called this method the "Reliability Pricing Model" (RPM). Key elements of the RPM are (1) a forward market centralized auction conducted three years in advance of delivery; (2) locational valuation to account for areas suffering grid congestion; and (3) a "demand curve" which defines the relationship between price and adequacy of resources.88

The forward market auction is held annually in May, and they set rates for June to May three years in advance of the date the power must be made available. Generators offer their capacity in response to the demand curve, and PJM clears offers in merit order until such time as it has acquired sufficient generation to meet its target reserve margin. In 2013, PJM set up the capacity markets to allow for up to three subsequent incremental forward market auctions to ensure no shortfall may arise. These auctions are operated in the same manner as the main auction.89

Capacity prices are set for regions within the PJM grid. The regions have been developed using the same thinking that is behind locational marginal pricing: the hope that higher prices in more constrained regions will incent investors to build more generation and/or transmission capability in those areas.

Consumers are required to pay the capacity cost through a formula that multiplies Peak Loading Capacity Tag (also known as a customer’s “Peak Load Contribution”), scaling factors, an RPM rate and the number of days. The PLC tag is based upon the customer’s usage during the five grid peak usage hours within the applicable PJM territory during the preceding summer.90 The PLC tag is thereafter multiplied by zonal scale and other factors, thereby setting the

88 Id., at 2.
89 See “RPM Incremental Auction FAQs,” http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/rpm-incremental-auction-faqs.aspx. The number of subsequent auctions required has since been reduced.
90 The cold winter of 2014, and the unusually high peak loading this led to, may require PJM to include winter months in the calculation in the future.
consumer’s capacity cost obligation. Of these, only the PLC is within the control of the consumer. The customer can try to reduce its capacity costs by ensuring that its peak usage does not coincide with the PJM five highest peak hours.

In trying to exert control over the PLC, it is important to understand that the PLC is set by the prior year’s peak consumption. Accordingly, if a consumer did nothing to during the summer of 2013 to shed load on any of the five grid peak hour dates, nothing can be done to reduce capacity charges for the summer of 2014. Most CRES providers, as a courtesy, monitor weather conditions during the summer and send out advance notices to their customers that certain days are likely to be one of the system’s five peak hour dates. Consumers can then react to this notice by shedding load as much as can be endured during those likely peak hours. In so doing, the consumer may be able to ensure that its peak load does not coincide with the system peak load, and thereby reduce the consumer’s capacity costs for the following summer.\footnote{91}

PJM’s capacity auctions identify costs for different zones within the PJM territory, four of which are located in Ohio: ATSI, Duke Energy, Dayton and AEP. ATSI (American Transmission Systems, Inc.) is First Energy’s transmission subsidiary and was integrated into PJM in 2011. American Transmission Systems, Inc. (ATSI)’s zone covers northern Ohio and part of Pennsylvania. In years from 2007-2012, the clearing prices at the principal capacity auctions have been relatively low, falling well below $50/MW-day.\footnote{92} See Figure 11 below.

Beginning with the auction conducted in the spring of 2012, however, this changed. Clearing prices in the ATSI zone, which covers territories controlled by Toledo Edison, Ohio Edison, Cleveland Electric Illuminating Company and Pennsylvania Power, rose to nearly $300/MW-day. Accordingly, for consumers in the ATSI zone, capacity charges will rise considerably in 2015. A consumer with a 60% load factor in the summer 2014 during the peak contribution periods will pay about $20/MW-h, or $0.02/kW-h. See Figure 12, below. For large industrial or commercial consumers, this could well mean millions of dollars in additional electricity costs.\footnote{93} For this reason, large scale electricity users will want advance notice of the likely five peak system hours during the summer of 2014, and shed as much load as possible during those times.

In the auction held in 2013 (for the 2016-17 Delivery Year), prices came back down somewhat. This was largely in response to imported electricity from outside the PJM territory. Imports from the west, primarily Midwestern Independent System Operator (MISO), increased to over 7000 MW as a result of the high capacity charges awarded from the 2012 auction. The result is that capacity costs in the year 2016-17 will drop back under $100/MW-day, even for the more congested ATSI zone.


\footnote{92} Because the incremental auctions have been relatively small, they are ignored for purposes of this discussion.

\footnote{93} Cleveland State University, for example, consumes roughly 50 million kW-hrs per year, with a load of about 10-12 MW. A capacity charge of $0.02/kW-hr would generate a cost for Cleveland State of around $1 million dollars for the year.
Figure 11: RPM Clearing Prices in $/MW-Day

![Bar chart showing RPM clearing prices from PY 08/09 to PY 16/17 for different companies.]

Data Source: GDF SUEZ, *The State of Electricity: Ohio*

Figure 12: RPM Clearing Prices in $/MWh (60% load factor)

![Bar chart showing RPM clearing prices from PY 08/09 to PY 16/17 for different companies.]

Data Source: GDF SUEZ, *The State of Electricity: Ohio*
c. Transmission Charges

In Ohio, transmission charges are assessed to CRES providers directly from PJM only in the AEP territory. The AEP CRES providers pass through the charges as an addition to their energy, capacity and ancillary services charges. In the FirstEnergy, Duke and DP&L territories, the transmission costs are assessed from PJM to the EDUs, who then pass the transmission charges to customers as a non-by-passable charge alongside the distribution charge.

Transmission charges that are passed through by PJM are designed to recover the transmission owners’ costs for transporting power over the portion of the interstate transmission grid that PJM actually, functionally operates. The transmission rates are regulated by FERC.

d. Ancillary Services
Ancillary Services, which typically run about $2-4/MWh, is the term used to describe an assortment of charges incurred by PJM for managing the grid.94 There are two general categories of ancillary services provided by RTOs: regulation services and operating reserves. The regulation services provide any short-term adjustments that might be needed to maintain system frequency. Operating reserves provide backup power to be made available in the event of a capacity shortfall or other emergencies.95 The categories of ancillary services listed in the PJM Guide include, among other charges: PJM Administration fees, transmission owner scheduling, generation deactivation, “black start” service, synchronized reserve, frequency response, and day-ahead scheduling reserve.

CRES providers usually pass through ancillary costs as a fixed cost. However not all the ancillary costs are necessarily fixed. In particular the cost of “Balance Operating Reserves” (BOR) can be dynamic, as the CRES providers discovered during an unusually cold January 2014. Members of the Retail Energy Supply Association registered concern not only over the record BOR charges that month, but also over the lack of transparency over how those charges were assessed. Many of the CRES providers were left to pay out of pocket for the cost overruns, with two even defaulting. That left them petitioning the PJM board of managers for more transparency and an explanation for the high BOR costs.96

E. Total Electricity Cost in Ohio

In Ohio, the Standard Service Offer sets the total price that the CRES providers will have to beat if they hope to sell power to the large commercial and industrial electricity consumers. Since the SSO usually incorporates a market-based auction for wholesale power, this may not always be easily done. However there may be other reasons for consumers to prefer CRES providers to the default price than just a lower fixed cost of power, including some of the options that CRES providers make available to manage energy costs (see section IV(C) below).

Assuming that the consumer will purchase power from a CRES provider, we can summarize the total costs of electricity in Ohio in the following table:

Table 2: Example of Shopping Customers Cost Components – Summer 2013

<table>
<thead>
<tr>
<th>COST COMPONENTS</th>
<th>AEP CS</th>
<th>AEP OP</th>
<th>DPL</th>
<th>Duke</th>
<th>FE-TE</th>
<th>FE-OE</th>
<th>FE-CEI</th>
<th>ALL UTILITIES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-Passable Utility Charges</td>
<td>19%</td>
<td>28%</td>
<td>17%</td>
<td>19%</td>
<td>27%</td>
<td>29%</td>
<td>27%</td>
<td>17% 29% 24%</td>
</tr>
<tr>
<td>Distribution</td>
<td>14%</td>
<td>12%</td>
<td>15%</td>
<td>18%</td>
<td>22%</td>
<td>16%</td>
<td>21%</td>
<td>12% 22% 17%</td>
</tr>
<tr>
<td>Transmission</td>
<td>9%</td>
<td>8%</td>
<td>5%</td>
<td>5%</td>
<td>4%</td>
<td>4%</td>
<td>4%</td>
<td>4%  9% 5%</td>
</tr>
<tr>
<td>Electricity</td>
<td>51%</td>
<td>45%</td>
<td>54%</td>
<td>50%</td>
<td>41%</td>
<td>44%</td>
<td>41%</td>
<td>41% 54% 47%</td>
</tr>
<tr>
<td>Capacity</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>2%  3% 3%</td>
</tr>
<tr>
<td>Ancillary Svs</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>2%</td>
<td>3%</td>
<td>2%</td>
<td>2%  3% 3%</td>
</tr>
<tr>
<td>Losses and Other</td>
<td>2%</td>
<td>2%</td>
<td>3%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>2%  3% 2%</td>
</tr>
</tbody>
</table>

Charged by Utility (EDU) regardless of shopping

Charged by CRES only if shopping

94 Braun, at 21.
95 Caplan and Brobeck, at 5.
Current electricity costs in Ohio have four principal components: electricity (CRES provider), Non-By-Passable charges (EDU riders), distribution costs (EDUs), and transmission costs (EDU for non-AEP territories, and CRES cost for AEP territories, through a PJM pass-through). Table 2 sets forth a range of electricity costs from the CRES provider from between 41 to 51% of the total cost of electricity. Utility distribution costs range from a low of 12% (Ohio Power) to a high of 22% (Toledo Edison). Non-by-passable charges range from 17% for Dayton Power & Light to a high of 29% for Ohio Edison.

We can expect that capacity charges as passed through by CRES providers on behalf of PJM will soar in 2014 and 2015 in response to recent capacity auctions, especially in Northern Ohio. As such, capacity will become another major component of the total cost of electricity.

By way of example, Cleveland State University had the following 2013 costs for electricity for its Rhodes Tower facility (roughly a 10 MW load):

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation/Capacity charge</td>
<td>4.1 cts/kW-hr</td>
<td>(CRES provider charge)</td>
</tr>
<tr>
<td>Distribution/Non-Bypassable</td>
<td>1.3</td>
<td>(EDU charge)</td>
</tr>
<tr>
<td>State Tax</td>
<td>0.3</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>5.7</td>
<td></td>
</tr>
</tbody>
</table>

Cleveland State University is in the Cleveland Electric Illuminating Company (First Energy) EDU territory. It acquired power from a CRES provider under a two-year contract that began in the summer of 2012, and was negotiated in the spring of the same year. Accordingly, in 2013, and under a contract negotiated in 2012, CSU’s electricity costs were 24% distribution/riders/transmission costs and 76% electricity/capacity costs. CSU anticipates that its capacity costs will go up significantly in the summer of 2014, however, as a result of the capacity auction of 2011.

Figure 14: Structure of Electricity Retail Prices, 2013
IV. Special Problems and Considerations for Electricity Markets in Ohio

A. Energy Market Issues

1. Locational Marginal Pricing and Electricity Markets

The delivered cost of electricity for a specific location is determined by a mixture of regulated and unregulated markets; the generation cost is unregulated, while the transmission and distribution cost is regulated. Generation costs, however, can never be completely segregated from delivery. Perhaps this is made clearest by the concept of Locational Marginal Pricing, or LMP, pursuant to which the cost of generation is merged with the cost of delivery to identify market price at a given location on the PJM day ahead and real time markets.

It is important to remember that LMP is operated by PJM for its real time and day-ahead markets – not for the bilateral markets, where the majority of sales take place. However the LMP informs the CRES providers about transmission congestion costs associated with delivery to specific locations.

Locational Marginal Pricing is a construct developed by utilities to identify the “least cost, security constrained dispatch” of electricity. PMJ defines it as the “cost to serve the next MW of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits.”\(^97\) It is designed to represent the instantaneous price of electricity at any given point in the grid, and to reflect the instantaneous “short run marginal cost” of an incremental unit of load at a particular location.\(^98\) It has also been defined as the “generation marginal cost” plus “transmission congestion cost” plus “cost of losses.”\(^99\)


\(^{99}\) Locational Marginal Pricing Overview – Western Area Power Administration, found at [http://www.wapa.gov](http://www.wapa.gov).
The concept of short run marginal costs (SRMC) is “fundamental to understanding” day ahead and real time electricity markets. Under traditional economic theory, in perfect competition, market price is “equal to marginal costs to producers.” The purpose of marginal cost pricing in electricity markets is to try to approximate “perfect market” conditions. The short run marginal cost is “the extra cost necessary to deliver an additional kilowatt-hour of electricity to a customer at a particular time and location.” The prices depend primarily upon fuel cost at the marginal electricity generating plant, as well as line congestion and losses.

LMP can be broken down into three components: (1) system energy price, plus (2) transmission congestion charge plus (3) the cost of marginal losses. System energy price represents the optimal dispatch price, ignoring congestion. It should be the same price for every location within PJM and is calculated for both day ahead and real time markets. Real time LMPs are calculated and posted on five-minute intervals.

Transmission congestion cost is principally the cost of line impedance, or the opposition to power flow. The higher path of impedance results in more opposition to power flow, more line losses, and more costs. Higher voltage, shorter lines, multiple parallel paths and fewer transformers will normally mean lower impedance. Transmission congestion cost is calculated using the cost of marginal units controlling constraints and “sensitivity factors.” It is calculated in both day ahead and real time, and the generators are paid the congestion price. As a result, transmission and generation markets, and therefore regulated and unregulated markets, inevitably merge in determining the LMP.

The cost of marginal line losses represent transmission losses priced according to loss factors which are calculated at a bus. It represents the percentage increase in system losses caused by a small increase in power injection or withdrawal. It is also calculated for both the day ahead and real time markets. Like congestion costs, it is paid to the generator, even though this is a transmission loss.

The LMP price is determined by the marginal cost of all producers and the winning auction bid for the most expensive power required to meet the last unit of electricity required. To make money, a producer will bid on a supply requirement at a price higher than its short-run marginal costs. If, however, that price turns out to be greater than the market-clearing price, its bid will not be accepted and the sale is lost. Accordingly, electricity producers should bid a price

---

100 Id.
103 Id. at 7349.
104 [PJM, supra, at 15.](http://ac.els-cdn.com/S0301421511006811/1-s2.0-S0301421511006811-main.pdf?_tid=1133a55e-c012-11e3-a740-00000aadcb35e&acdnat=1397067138_6c1a0924fecefe12309744545d3e0b5)
106 Id. at 17. Sensitivity is developed through a complex set of algorithms designed to approximate transmission costs.
107 Id.
108 A bus is the physical location where power is downloaded, typically at a substation, where the electricity is converted from higher to lower voltage.
109 [PJM, supra, at 20.](http://ac.els-cdn.com/S0301421511006811/1-s2.0-S0301421511006811-main.pdf?_tid=1133a55e-c012-11e3-a740-00000aadcb35e&acdnat=1397067138_6c1a0924fecefe12309744545d3e0b5)
that is close to or equal to its marginal costs – to avoid losing the sale.\footnote{P. Pikk, supra, at 52.} In this way, the LMP most closely resembles the short run marginal cost of electricity.

However utilities will try to maximize their profit, as they must, so the LMP cannot reproduce exactly the short run marginal cost of delivering electricity. In a “bid-based” marketplace, generator price offers are substituted for generator costs, and the former will rarely equal the latter.\footnote{Hausman, supra, at xiii.} In the PJM territory, the market monitor imposes a 110% production cost offer cap to mitigate this problem.\footnote{Id. at xiv.} However the market monitor may not always catch overcharges.\footnote{Id. at xiv.} Further, often times there are elements of costs included that are not really marginal. In theory, truly marginal costs in the short run will be dictated by fuel costs. However an RTO may allow in its formula for the recovery of such things as the sunk costs of investments. And often times high cost marginal plants are built with the aim of operating only during peak periods, when the short run marginal costs will be highest.\footnote{Pikk, supra, at 50.}

Perhaps the biggest concern for LMPs has been the fear that certain energy suppliers that hold a dominant market position in a constrained area can act to artificially increase prices above competitive levels for a sustained period of time. Indeed, this is a concern for all electricity markets, be they on the bilateral or the PJM system. In Ohio, regulators have for some time sought to induce more CRES providers to be active in the Ohio market to ensure that this problem would not arise. As of March 2014, there are some 664 CRES providers licensed in the Ohio market. Even in 2007, prior to the recession that drove down wholesale prices, there was no clear indication that market power was a problem in the PJM territory.\footnote{Hausman, supra, at 60.} Nonetheless, the complexity of the LMP and other electricity markets make it difficult to draw firm conclusions about the opportunity for certain utilities to obtain and use market power.\footnote{Id.}

The FERC has established structural tests to identify market concentration and, if it finds no problem after deploying these tests, a presumption of no market power is found. The next level of oversight then occurs at the RTO, where the market monitor reviews overall market performance. This includes a review of both price trends and concentration metrics. PJM has an internal market monitor that produces reports on an annual basis and monitors the exercise of market power, as well as the evaluation of spot and bilateral markets to detect design flaws or other problems. It includes the imposition of caps on electricity costs of $1000/MWh and on generation resources if there is a failure of a “three pivotal supplier test.”\footnote{The $1000/MWh cap was lifted by the FERC for PJM as a result of a series of extraordinary January 2014 cold weather, which resulted in unusually high peak generation. See “FERC Lifts Price Cap as Cold Grips PJM,” RTO Insider, February 11, 2014, \url{http://www.rtoinsider.com/ferc-pjm-price-cap-0114/}.} This test requires that incremental generation from a “load pocket” can be replaced by other sources at less than 150% of the clearing price.\footnote{Id. at 67. See, generally, the discussion of RTO market monitors on pages 57-86.}

Some experts have raised concerns that FERC and the PJM Market Monitor have not been active enough in constraining cost increases. For instance, experts with the American Public Power Association have argued that RTO market structures contribute to higher pricing. The authors note that the single clearing price on both the energy and capacity markets,
especially in the absence of cost-based alternatives, enables generators to reap very high profits on low cost generation. Moreover, the authors say, the RTO markets have been bloated with “never-ending layers of new markets and pricing policies” leading to a system so complex it is opaque to the consumers. The result is that the largest generators within PJM have enjoyed “higher earnings than one would see under regulation.” There is no shortage of literature on “market power in power markets,” much of it dating back to the 1990s when market restructuring first came to pass. Because of the ability of incumbent utilities to potentially control markets in certain areas, it will remain a matter to be watched closely by PJM, FERC and the electricity industry watchdog groups.

2. The Problem of New Generation

One of the principal reasons given for developing the LMP has been to encourage capital investment into generation “where the power ... produce[d] will have the greatest value.” In theory, higher LMP prices in congested areas will encourage utilities to place new generation in locations where it will “exert downward pressure on prices.” However this theory has proven to be flawed.

Simply, utilities do not respond to short run marginal pricing increases with long term cost recovery generation projects. To begin with, the obstacles to investing in congested areas can be problematic – these also tend to be where zoning restrictions and land, labor and fuel costs make building more difficult. But more importantly, utilities have little reason to risk generation development in an unregulated market based upon short term pricing trends. There is no guaranteed rate of return on generation if there is no regulated market. It makes more sense to invest instead into more transmission and distribution, where the rate of return is guaranteed. This is especially so in places where the utility can, by building more grid, create a new market for its own nearby excess centralized generation capacity.

The result of this dual regulated/unregulated electricity market strategy is that utilities will prefer to build more grid over developing new generation – even when it might make more financial sense to the consumer to use distributed generation rather than to build additional grid. Indeed, restructured markets have had the unfortunate effect of causing utilities to resist distributed generation, and to seek the imposition, when possible, of regulatory roadblocks to their development. These include such things as excessive standby fees, exit fees, net metering limitations and a suppressed market for locally generated surplus electricity. This also discourages the development of clean energy technologies such as wind, solar and combined heat and power systems, which tend to be distributed in nature.

This is perhaps most clearly demonstrated by the approach of FirstEnergy Corporation, which recently announced it would refocus its efforts on the regulated side of its business after

---

119 E. Caplan, supra, at 7.
120 Id. at 8-9.
121 Id. at 13 (citing internal analyses conducted by APPA).
122 Id. at 18 (citing “Answer of the Supporting Companies,” FERC Dockets OA97-261-000 and ER97-1082-000, December 31, 1996, p. 8-11).
123 See e.g. R. Michaels, “MW Gamble: The Missing Market for Capacity,” The Electricity Journal, at 56-64 (December 1997) (“Reluctance to commit to generation in anticipation of markets may indicate that we have not thought through the consequences of the institutions we are putting in place.”)
124 Caplan, at 18.
125 See, generally, Pikk at 52-54 for a discussion of how short term marginal pricing fails to develop generation markets, especially for renewable energy technologies.
incurring some disappointing results from competing in the electricity generation market. FirstEnergy CEO Tony Alexander stated that the decision to focus on wires instead of generation was dictated by the ongoing sluggish economy, which had led to a significant drop in wholesale prices for electricity. Mr. Alexander went on to say that, “[a]s we see the company today and the opportunities going forward, we believe that focusing our efforts primarily on regulated operations is the best thing for the company.” This strategy comports with FirstEnergy’s previously announced plans to invest 2.8 billion dollars into its delivery systems in the next four years -- investments that it anticipates it will recoup (plus a profit) through the regulated tariff system, and which will make the company more valuable.

The investment community has approved of this new direction for FirstEnergy. Moody’s Investors Services, for instance, responded by noting that, “we view investment in transmission assets positively as they typically earn a strong FERC-approved return in excess of 11%, generate predictable cash flows and have minimal operating risk.”

This is an entirely understandable investment strategy. But as the utilities become further entrenched in the business of wires only, the more they will resist any regulatory strategies that may devalue the grid. This will include not only distributed generation, but also programs such as energy efficiency and demand response. In the meantime, the electricity industry and our policy makers stand at a threshold – deciding whether to invest billions of dollars that could lock us into a plan of traditional centralized generation tied to a ubiquitous grid, or to invest instead into a plan calling for smart micro grids, distributed generation and renewable power.

But it is not just the fact that there is no certain cost recovery mechanism in place in a deregulated market that impedes the build out of new generation. Higher LMP rates provide an incentive for incumbent generation to maintain supply constraint. Again, this can best be demonstrated by the response to the closing of coal plants in Ohio: no significant new generation plants are in the plans for FirstEnergy or the other utilities, despite the closing or planned closing of several large coal plants. Studies have found that such closings actually benefit incumbent generators who continue to operate with increasingly constrained supplies. As a result, merchant generators have a strong interest in minimizing new market entry. Indeed, in the PJM

---


128 Funk, supra, at 1. See also Howland at 1.


130 FirstEnergy has steadfastly opposed energy efficiency programs in Ohio, including supporting several efforts to overturn the energy efficiency portfolio contained in SB 221. See e.g. M. Kasper, “Ohio Senate Republicans Launch Attack on State’s Renewable Energy Law,” Climate Progress, March 31, 2014, found at: http://thinkprogress.org/climate/2014/03/31/3420880/ohio-republicans-attack-renewable-law/ (discussing proposed SB 310 and the history of utility efforts to overturn the energy efficiency standards in Ohio).


territory, merchant generators have won rule changes that have imposed minimum pricing on
new generation to prevent such generation from lowering market prices.\footnote{Id. at 7-8.}

\section*{B. Consumer Purchase Strategies and CRES Provider Products}

In recent years, many consumers are choosing to purchase electricity from CRES
providers as CRES providers have been able to beat SSO prices.\footnote{As of October 2013, in AEP Ohio territory, for instance, 42% of the retail load was SSO, and 58% was from CRES providers. Most of the retail load was residential, as 80% of commercial customers and 64% of industrial customers used CRES providers. \textit{See} K. Abbott, “AEP Ohio Seeks to Rely on More Market-Reflective Rates for Default Service for 2015-18,” \textit{Energy Choice Matters}, December 23, 2013, found at: http://www.energychoicematters.com/stories/20131223d.html.} Electricity purchased from
the CRES provider is purchased typically either as a fixed “all inclusive” price or through a
“block and index” strategy. The fixed-price option provides the least amount of risk for the
consumer, but often carries with it premiums. The price includes the CRES provider cost-of-
energy plus the pass through expenses that are assessed by PJM. These sorts of contracts are
popular with consumers that require a high degree of predictability in their energy costs, and
want to minimize power consumption management obligations. Fixed price contracts are usually
available from CRES providers for one to three year periods.

The block and index strategy can be attractive to large-scale power consumers who are
able to exert some management over consumption behavior as this strategy provides elements of
both predictability and cost management. Under this model, the consumer hedges portions of its
load at a fixed price, leaving other portions open to market fluctuation. How much a consumer
hedges will depend upon market conditions and the risk tolerance the customer can bear.

The “block” portion is the volume of electricity that is purchased at a fixed price. Any
electricity purchased over and above this block amount is purchased at the then-going market
rates, usually on an hourly basis. Since most consumers have peak periods of use that go
through cycles, one strategy is to purchase as a block the power required as the base load, and to
purchase as index the portions of the power required at peak times. It is the more expensive
peak loads that consumers hope to manage. During times of expensive power, the consumer can
choose to slow down operations, shift the loads to less expensive times, or to just bear the more
costly power as may be required.

Block and index pricing schemes are most beneficial to those consumers who either have
predictable usage patterns (e.g. manufacturing shifts) or who can shed load through either
management or self-generation. It is considered a “medium” risk strategy for purchasing power,
since normally most of the load is purchased at a fixed rate.\footnote{See e.g. “Electricity Pricing Options,” \textit{Better Cost Control}, at: http://bettercostcontrol.com/electricity-pricing-options/#blockandindex}

Other market strategies can be found that are more risky, such as “LMP index pricing”
(based upon the hourly clearing price on the LMP market) or “heat rate pricing” (based upon
natural gas pricing). These strategies can be attractive to companies that actively follow the
power industry through risk and trading managers. In addition, there are other strategies that the
CRES provider can add to their package to manage cost, such as trigger or tranche pricing,
whereby the consumer identifies a threshold price pursuant to which the CRES provider is
authorized to purchase blocks of power.\footnote{Id.}
C. Constraining Capacity Auction Prices

In recent years, as wholesale prices have dropped, the most controversial aspect of the PJM electricity markets has been the capacity charges. This is especially so for the ATSI (FirstEnergy) zone in northern Ohio, where capacity prices for 2014 and 2015 have dramatically increased as a result of auctions in 2011 and 2012. The high prices, according to capacity market theory, should trigger the development of new generation in those zones where capacity prices are high.

Indeed, capacity prices for ATSI and the other Ohio regions did drop significantly with the auction of 2013 (for 2016/2017). Yet this dramatic drop was not in response to new generation – instead it was in response to generation being supplied from the Midwestern Independent System Operator or further west. Over 7000 MW of imported capacity was offered into the PJM RTO, an increase of over 90 percent from the 2012 auction. Nearly all of the offered generation cleared the auction, causing the precipitous drop in capacity prices. 137

In September 2013, then-PUUC Commissioner Todd Snitchler filed comments into FERC proceedings examining the effectiveness of centralized capacity markets in RTOs. In these proceedings Commissioner Snitchler argued that allowing utilities in the MISO RTO to export capacity into the PJM RTO comes with considerable risk to consumers in the PJM market: it fails to provide “iron in the ground” within PJM, and fails to address the generation shortfall that higher capacity prices are designed to correct. 138

Evidence to date, however, is that three year ahead price signals in the capacity market do not spur long-term investments into generation. The reasons for this are the same as that for new generation – there is no mechanism for certain recovery of investment. Indeed, there is evidence that utilities profit handsomely from lack of generation capacity, just like they do for sales of electricity in the constrained LMP markets. 139 Nevertheless, the FERC has since ordered a limitation to imported capacity into the PJM market. 140

Commissioner Snitchler also raised the argument that generation in the MISO RTO, where the utilities continue to be vertically integrated, is subsidized, and that this is “detrimental to a fully competitive centralized capacity market design.” 141 Commissioner Snitchler did not specify what subsidies he was referring to, but assuming that the principal subsidy at issue is the ability of vertically integrated companies to pass through the costs of generation to their captured customers, Ohio’s utilities have no shortage of that sort of generation itself. Nearly all of Ohio’s generation was built under the old vertically integrated, fully regulated model of cost recovery – including any excess capacity. But more importantly, it is unclear how restricting importation of generation capacity built under a regulated model will cause more generation capacity to be built.

Commissioner Snitchler explains why: “Because the [PJM Reliability Pricing Model] lacks financial certainty for generation from year to year, it is apparent the companies are relying more on transmission upgrades to relieve congestion and constraints…. For example, utilities are

---

138 Id at 11.
139 See e.g. G. Meuneir, supra, at 1306-15.
141 Id.
pursuing transmission expansion to resolve constraints in the ATSI zone, as opposed to building new generation facilities.”142 In short, utilities will not build new generation in response to short term capacity price signals, so long as their returns are not guaranteed. Restricting imports will not change this. But they will, however, build new transmission, notwithstanding the threat of imports, because transmission enjoys guaranteed rates of return of over 10%. So it appears that importation of capacity into PJM is having little effect on either generation or transmission in the ATSI zone.

Commissioner Snitchler raises an important policy question with his observation, however; it speaks to what Ohio sees as its future for utilities. It is for policy makers to decide if the current system makes sense in view of the societal goals of developing a more secure and smarter grid, with cleaner energy at reasonable prices. It is apparent that the current regulatory system encourages utilities to build more grid and less generation. Reliance on centralized generation and building more grid may not be the model that we want for the future, when so many new technologies rely on distributed generation.143 But once the utilities make these major investments, we may be locked into this paradigm for the next 50 years.

The utility business is aware that it is at a crossroads – facing disruptive new technologies in generation, storage, efficiency and demand side management, among others. Experts anticipate that the future grid will act like a “giant battery” – where power is put in and taken out by the consumer.144 Utility commentators point to the Google acquisition of Nest as an example of where the future of the grid can be found: the Internet will transform how we use and purchase electricity, enabling demand side optimization. Demand side optimization will also require generation optimization, which can be best accomplished locally in micro-grids. And it will also create downward pressure on demand, requiring utilities to adopt different models for growth.145

Yet utilities today do not have the capability of managing distributed generation because it has always followed a “central station approach.” Moreover, current regulations do not properly incent utilities to develop this capability.146 As one utility CEO noted, “society needs to regulate utilities with an eye towards motivating them to do the things that society wants out of them. That’s a pretty obvious concept, but a very novel one when it comes to utility regulation.”147 As Ohio utilities, especially in northern Ohio, stand on the threshold of making multi-billion dollar investments into a long-term future betting on traditional centralized generation, policy makers would do well to consider this insight. Utilities behave, as they must, in accordance with how we regulate them.

---

142 Id., at 13.
145 Id.
146 Id.
147 Id., quoting Ron Binz, former CEO of Duke Energy.
D. Demand Response and Energy Efficiency Programs

1. Programs in Ohio

Ohio has, through Senate Bill 221, created programs for energy efficiency and peak demand reduction. Utilities can use both energy efficiency and demand response programs to meet peak demand reduction requirements.148 Energy efficiency under SB 221 is designed to reduce demand, and is largely behind the meter. It is paid for through a non-by-passable charge, the DSE2 rider. However large-scale electricity users (greater than 750 MW-hrs per year) can obtain from the PUCO a waiver of this charge by undertaking energy efficiency work themselves. They may also choose to get a rebate from their EDU in lieu of the waiver.149

In recent years, Ohio utilities, led by First Energy, have waged an ongoing war against the energy efficiency mandates,150 presumably because energy efficiency reduces their volume of sales. So long as utilities are regulated in a fashion that rewards them for sales volume, we can expect this war to continue. Indeed, the Edison Electric Institute, a trade group for the IOUs, and the Natural Resources Defense Council jointly called for electricity regulators to stop linking utility rates to electric sales for this reason. Such a move would help enable the development of both distributed generation and energy efficiency.151

Both the demand response programs and the energy efficiency programs can be bid into the PJM capacity auction, insofar as they both can serve to reduce the amount of capacity required. However, utilities have been reluctant to participate through PJM's programs. Ohio PUCO Chairman Todd Snitchler argued to the FERC that energy efficiency and demand response programs are not as reliable as generation capacity, and that accordingly RTOs should heavily discount such bids.152 Even so, the PUCO has since made it a requirement that the utilities bid their demand response and energy efficiency programs into the capacity markets

148 Ohio R.C. 4901:1-39(E)(2)
150 In response to this pressure, Ohio’s energy efficiency mandate was frozen for two years in June of 2014 by SB 310, pending a study by of the economic effects of this and the renewable portfolio mandates. See T. Knox, “The Freeze is On,” Columbus Business First, June 13, 2014, found at: http://www.bizjournals.com/columbus/news/2014/06/13/the-freeze-is-on-kasich-signs-s-b-310-halts.html. For other utility efforts, see also e.g., proposed Ohio Senate Bill 58, promoted in the fall of 2013, which sought, among other things, to move energy efficiency from behind the meter to the generation, transmission and distribution side. The result of this strategy would enable the utilities to maintain growth in sales volumes. The utilities eventually cancelled the vote on the proposed bill, apparently concluding it did not have sufficient support in the Ohio Assembly. See D. Gearino, “Vote Canceled on the Utility-Friendly Bill to Change Ohio Energy Rules,” The Columbus Dispatch, December 5, 2013, http://www.dispatch.com/content/stories/business/2013/12/04/vote-on-energy-rule-revamp-postponed.html
151 See EEI/NRDC Joint Statement to State Utility Regulators, February 12, 2014, http://s3.amazonaws.com/dive_static/diveimages/ene_14021101a.pdf (recommending that the retail electricity business not be regulated as if it were a commodity business dependent upon the growth in electricity use to keep its owners financially whole.)
going forward.\textsuperscript{153} It is unclear how much of an effect this will have going forward, but it certainly could act as a restraint on rising capacity costs.

2. Demand Response Programs Available from PJM

PJM sponsors an emergency demand response (DR) program\textsuperscript{154} that is designed to reduce power consumption during times of exceptionally high peak usage. The purpose behind the program is to mitigate the need to build expensive new generation. The program pays for electricity consumers to reduce their demand during specified peak events that occur between June and September. PJM, upon recognizing an event requiring system-wide response, sends out a notice to customers and/or to DR providers requesting curtailment in consumption. Those who participate in the program are paid on a per MWh basis for their curtailment.

A consumer typically participates in the program through a contract with a DR provider to curtail demand by a certain amount for a period of time, upon notice of the event. Participation also requires that the consumer demonstrate, through test events, its ability to respond as contracted should a PJM event be called. Under the 2013 rules, emergency demand response events could be called up to ten times per year, and may last up to six hours. However the history has been that they occur 1-5 times per year, and last only a few hours.\textsuperscript{155}

Participants can earn money for simply having the demand response on standby, and if no event is called, the participant earns 100\% of the amount they would have earned if there had been an event. However if there is an actual emergency event, the performance during the event sets the amount earned. Actual payments depend on the DR provider contract, but are usually based upon the duration of the event and the MWs of load dropped. Accordingly, if the participant fails to perform, no money is earned. Partial performance, likewise, garners partial payment. Most demand response contracts do not penalize the participant for failing to perform.

Common demand responses include reducing air conditioning loads through such strategies as pre-chilling and thermal storage. Another common strategy is to rely upon backup, on site generators, especially cogeneration facilities. They also include reducing use of mechanical operations and lighting. Finally, for those who participate in the emergency demand response program, emergency events do not count as one of the grid’s top five “coincident peak” hours for purposes of determining peak load contribution and capacity charges.

In addition to the emergency DR program, new programs have been developed, including programs for Capacity Market, Economic Load, Synchronized Reserve and Frequency Regulation demand response.\textsuperscript{156} Under the economic demand response program, consumers can voluntarily reduce load in response to spikes in wholesale market prices. Under this plan, the

\begin{itemize}
  \item \textsuperscript{153} See A. James, “How a Utility’s Sketchy Efficiency Practices Could be Costing Ratepayers More than $400M,” \textit{Greentech Media}, July 12, 2013 (noting that PUCO’s requirement that First Energy bid energy efficiency into the PJM capacity market helped northern Ohio see a 56\% reduction in capacity charges in the May 2013 auction); found at: http://www.greentechmedia.com/articles/read/how-a-utilities-shady-business-on-efficiency-could-be-costing-taxpayers-more. Environmental, consumer and business groups all lobbied the PUCO for this requirement.
  \item \textsuperscript{154} The PJM emergency demand response program is also called the “Interruptible Load for Reliability” program.
  \item \textsuperscript{156} See e.g. “Comverge: Energy Made Better,” found at: http://www.comverge.com/commercial-industrial/demand-response/PJM
\end{itemize}
participant contracts with the demand response provider to give notice of wholesale market prices having exceeded an agreed upon price threshold, whereupon the participant can choose to reduce its consumption. The participants are thereupon paid a share of the locational marginal price in accordance with their reduction.157 The synchronized reserve market is a year around demand response program designed to assist with system reliability. Customers are paid if they can shed 100 kW within 10 minutes (regardless of whether an event is called).158

Certain consumers who have control over their operations such that they can respond to two-second notification to either shed or increase load can also be paid for responding to the Frequency Regulation demand response.159 The program is designed to enable PJM to maintain electricity quality as well as quantity. It requires the installation of advanced telemetry and automated control equipment on the consumer’s site.

Demand Response programs are likely to become an increasingly significant part of the strategy for management of electricity for large commercial and industrial consumers. The ability to respond to DR programs, together with the need to constrain capacity costs by reducing consumption during peak grid demand periods, may also drive more on-site generation that has the capability of producing power during peak demand, such as solar power and natural gas fueled combined heat and power systems.

V. Conclusions

Electricity markets in Ohio have become more complex for consumers since deregulation. What was once presented to the consumer as a single fixed rate for generation, transmission and delivery of power has now become a potentially bewildering list of component prices presented in a variety of products by a variety of companies. But the truth is that electricity costs were always complex – it was just not transparent to the consumer. Restructuring has just made this complexity available to the consumers to understand – if they choose to spend the time doing so. If they do not, they can simply default to the traditional utility fixed rate. In so doing, they have some comfort knowing that the PUCO exercises oversight in this process through the submission by the utility of an electric stability plan.

The architecture and complexity of restructured electricity markets were captured elegantly in a 2008 paper by Synapse Energy Economics.160 The chart identified all the players in the electricity market in a flow diagram, ranging from generation to delivery of the power to the end-user. This diagram serves nicely as a conclusion to this analysis of electricity markets in Ohio.

Figure 15: Restructured Electricity Markets

157 Id.
158 Id.
159 Id.
Source: Synapse Energy Economics.