MOVING TO BETTER RATE DESIGN

RECOMMENDATIONS FOR IMPROVED RATE DESIGN IN OHIO'S POWERFORWARD INQUIRY

AUTHORS & ACKNOWLEDGMENTS

AUTHORS
Dan Cross-Call, Becky Li, and James Sherwood

**Authors listed alphabetically. All authors are from Rocky Mountain Institute.*

CONTACTS
Dan Cross-Call, dcrosscall@rmi.org
Becky Li, bli@rmi.org

SUGGESTED CITATION
Cross-Call, Dan, Becky Li, and James Sherwood. *Moving to Better Rate Design: Recommendations for Improved Rate Design in Ohio's PowerForward Inquiry.* Rocky Mountain Institute, 2018. https://info.rmi.org/rate_design_recommendations_ohio

A version of this report was submitted to the Public Utilities Commission of Ohio in the PowerForward initiative of the commission.

ACKNOWLEDGMENTS
The authors thank the following individuals/organizations for offering their insights and perspectives on this work.

Madeline Fleisher, Environmental Law & Policy Center
Leia Guccione, Rocky Mountain Institute
Janine Migden-Ostrander, The Regulatory Assistance Project
Samantha Williams, Natural Resources Defense Council

ABOUT ROCKY MOUNTAIN INSTITUTE
Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

TABLE OF CONTENTS

About This Report

Modern needs and rapidly changing technologies have forced a rethinking of electricity system design, including of the utility business model, pricing approaches, and system planning. Rocky Mountain Institute works with utilities, regulators, and stakeholders across the electricity sector to understand these trends and create new solutions to build a cleaner, affordable, and secure power system.

This report was previously delivered to the Public Utilities Commission of Ohio to support its investigation of technological and regulatory changes in the electricity sector in the Commission's PowerForward initiative. The report was prepared by Rocky Mountain Institute and does not necessarily reflect the views of the Commission.

I. EXECUTIVE SUMMARY

Ohio's PowerForward initiative is a valuable opportunity to review trends in the electricity industry and to reflect upon how those impact Ohio's utilities, electricity customers, and fulfillment of state policy objectives. PowerForward is taking place at a time of aging power plants and grid infrastructure; dramatic changes in technical capabilities of power system technologies; rapidly declining costs of renewable energy sources; and new expectations for customers' relationship to, and services received from, their energy supply. These forces have created an environment that compels utilities and policymakers to take action to reposition the power system to effectively support a new era of energy needs.

Through the PowerForward initiative, the Public Utilities Commission of Ohio (PUCO) is reviewing "the latest in technological and regulatory innovation that could serve to enhance the consumer electricity experience," including through "future grid modernization projects, innovative regulations and forward-thinking policies."[1] Among a set of questions related to rate design, the PUCO has asked, "How can dynamic pricing and time-of-use rates be used to better align principles of cost causation and reduce energy consumption and demand for default service customers?"[2]

Rocky Mountain Institute works with public utilities commissions, leading utilities, and third-party energy service companies from across the US to provide strategic guidance and support for modernization to a cleaner, more resilient, and more affordable energy system. Drawing upon our research and work across jurisdictions, as well as investigation of Ohio utilities' rate structures and conversations with key actors in Ohio electricity markets, we compiled this memo to support the PUCO in its deliberations in PowerForward and related regulatory activities.

Summary of Recommendations

At this critical juncture in power system evolution, and electricity rate design in particular, we encourage the PUCO to consider the following recommendations and focus areas.

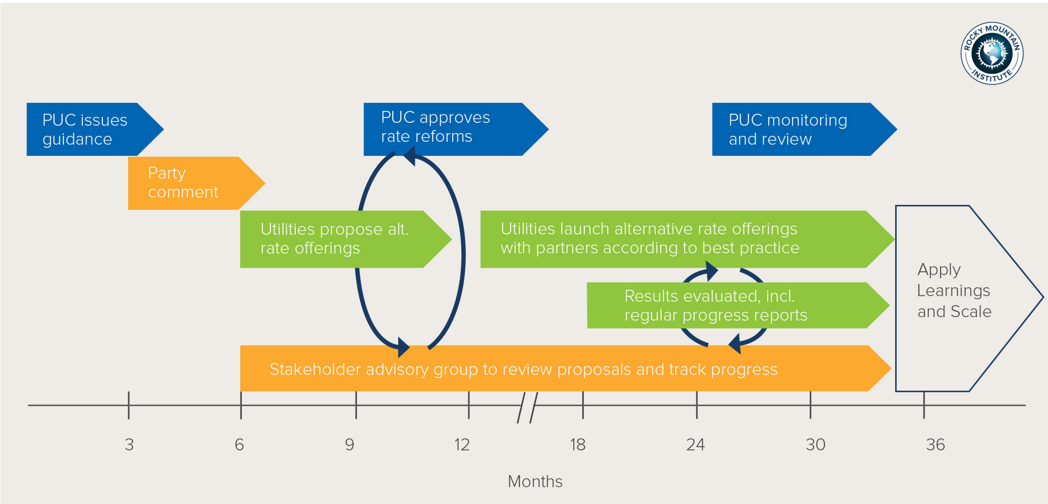
- **The PUCO should clarify the policy objectives it seeks to achieve through rate design** for distribution and default generation service, and potentially through competitive generation service to the extent that is within PUCO jurisdiction. Utilities and nonutility interveners benefit from clear guidance from regulators regarding what objectives should be the focus of their efforts to update rates and associated programs.
- In subsequent proceedings and rate cases, **the PUCO should evaluate proposed rates against established policy objectives.** This effort will be made stronger if objectives are supported by criteria measurements against which rate structures can be judged. Criteria could include, for example, measurement of estimated customer bill impacts or specified targets for reduced energy consumption and peak load.
- Alternative rate designs require nuanced determinations for design of pricing structures, as well as thoughtful program design and implementation. New rate designs that might, on their face, appear progressive and promising can underdeliver due to relatively simple but unattended design decisions. **Reforms should not proceed without careful attention to design and implementation.** Pilots can be an effective means to build experience and customer familiarity with alternative rate designs, but pilots must be conducted in a manner to maximize learning and scalability of results.
- Expanded roles for competitive retail electric service (CRES) providers afford promising opportunities, however CRES expansion also carries risks. As experienced by other states, risks include bill increases for vulnerable customers and erosion of electricity markets' alignment with state policy. **CRES expansion should be balanced with attention to ensuring appropriate roles for default service**

[1] https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/, accessed on February 27, 2018
[2] https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/, accessed on January 16, 2018

providers, including, for example, to provide high-quality rate options as a baseline for competitive providers to improve upon.

- As a next step, we encourage the PUCO to **develop specific guidance to set a path forward for rate design improvements,** including objective criteria by which rate designs will be evaluated, then **require utilities to propose rates and implementation plans that meet specified criteria.** A possible timeline for this process is shown below, with additional detail and suggestions for implementation described further in the Next Steps section of this memo.

FIGURE ES.1 POSSIBLE TIMELINE FOR RATE DESIGN REFORMS



II. CONTEXT: NEED AND OPPORTUNITIES FOR RATE REFORM

Pricing Reforms to Support a Reliable, Affordable Grid

Several developments are changing the rate design landscape. With flattening load growth, declining cost of renewable energy, and aging infrastructure in the power system, existing rate structures are not meeting the need for distributed energy resource (DER) integration, and in extreme cases are putting some utilities at risk of losing customers (i.e., "grid defection"). Meanwhile, increasing numbers of customers are ready for innovative rate offerings that provide the opportunity to better manage energy use and costs. These changes are moving the system toward a more integrated grid, where some customers become prosumers and utilities benefit from demand-side services to provide load flexibility and unlock additional values for customers and utilities alike. There is widespread recognition that traditional rate design, which bundles diverse costs under a simple structure of a flat rate plus a mix of customer charges and riders, is not up to the needs of a system with vastly different cost structures and a more diverse set of market participants.

Expanded Options for Electricity Pricing

In response to larger trends, actors across the utility industry are reevaluating approaches to price setting. This is reflected in three prominent trends:

1. Attention to unbundled cost and value components that have historically been embedded within electricity rates (i.e., not visible to customers)
2. Expanded time-based rates to better reflect system costs and support grid flexibility
3. Proposals for expanded demand charges intended to recover costs associated with customers' peak energy usage or "fixed" costs of energy delivery

Unbundled Cost and Value Components

Where historical rates blended all utility costs into a single (or limited set) of price variables seen by customers (e.g., fixed monthly cost plus $/kWh volumetric cost, with apportionment and differentiation between customer classes), there is a movement by utilities and regulators toward greater unbundling of cost and value components. This is motivated by a host of factors, including:

- Growth of restructured markets in which all costs are no longer borne by utilities alone
- Rise of DERs, which have made customers more than one-way consumers of electricity
- New capabilities for granular metering, allowing more accurate measurement and tracking of energy use as well as provision of other grid services (e.g., measurement and control by smart inverters)
- Resulting diversification of customers' relationship to their energy supply, including through energy efficiency, demand response, and distributed generation programs, which create a need for more accurate cost and value accounting to recognize and fairly assign costs and compensation for grid service

Unbundling of cost and value can be instituted many ways, with variations by jurisdiction as well as applicable technology or services (for example, with value-of-solar tariffs, net metering successor programs, or demand response program design). New York's ongoing "Value of DER" proceeding and Hawaii Electric Company's recently approved Demand Response Program Portfolio are examples of leading efforts to develop unbundled tariffs that assign cost and value in new ways beyond traditional rates or standard DER program designs.

Unbundling of rates can help modernize electricity markets and support more fair assignment of cost and value. However, it requires careful attention to ensure that costs are not imposed in a punitive or imbalanced manner. Critically, cost-of-service evaluations need to accurately account not only for costs imposed for different customers' use of the grid (whether by time or location of electricity consumption, or for integration of new customer-sited technologies) but should also reflect all values that customers may contribute (such as reduced generation and energy purchase requirements, cost savings from peak load reduction, or deferment of other capital expenses).

Time-Based Rates

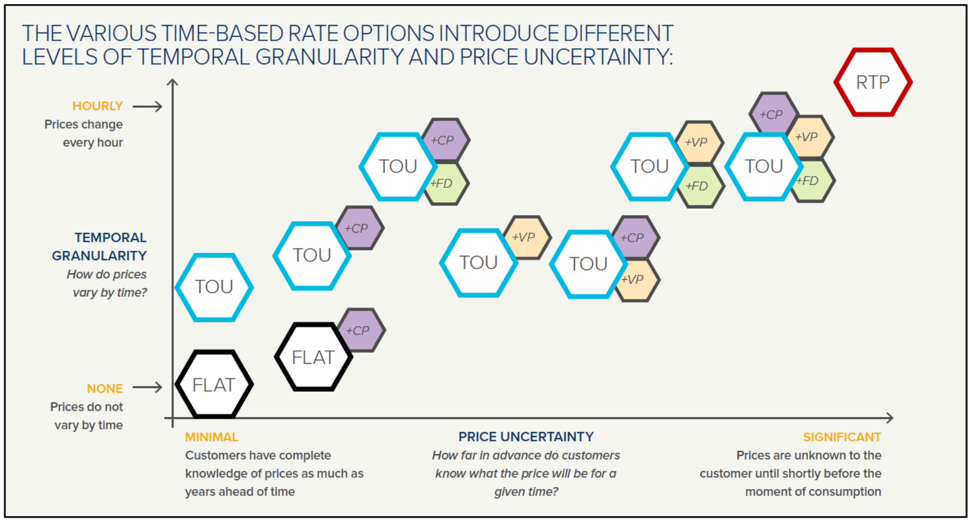
A related trend is to institute time differentiation into rates to reflect variability of grid costs within the day, as well as between days and across the year. Time-based rates can provide a price signal that more accurately reflects the changing cost of energy production and delivery throughout the day and between days or seasons, and have been shown to achieve significant peak load reduction without compromising customer satisfaction when designed well. Many time-based rates, however, suffer from bad design that is divorced from underlying grid conditions and not aligned with stated objectives, and that are implemented without adequate attention to customer education and communication. In recent years, a growing number of better-designed time-based rates have been launched, which provide valuable examples and experience to draw upon for improved program design.

Many options exist for setting time-based rates, with structures based on one of three foundations:

- **Flat rate.** Although not time-varying on its own, a flat volumetric rate (including inclining block rates) can be time-varying when coupled with a time-based modification (for example, critical peak pricing; see below).
- **Time-of-use (TOU) rate.** A TOU structure reflects historical temporal variation in system costs by setting different prices by time of day. Both prices and their applicable time period (i.e., which hours are "on peak" versus "off peak") are predetermined.
- **Real-time pricing (RTP).** An RTP structure provides prices that vary over short intervals (e.g., hourly) to closely reflect actual costs. Prices are not predetermined.

Additional modifications on these foundations provide variations to align rates with specific objectives for the program, including critical peak (CP), variable peak (VP), and flexible duration (FD) pricing. Figure 1 illustrates some approaches for time-varying rates. Depending on how much the prices vary by time (temporal granularity) and how far in advance customers would know what the price will be for a given time (price uncertainty), time-based rates can range from basic TOU rates, which incentivize load shifting in all days, to flat or TOU rates coupled with critical peak and other modifications that incentivize peak reduction targeted to critical days or hours of the year.[3]

FIGURE 1: BASE STRUCTURES AND MODIFICATIONS FOR TIME-BASED RATES



BASE STRUCTURES

Any time-based volumetric rate design will have one of these structures as a foundation

FLAT — While not a time-based rate on its own, a flat volumetric rate—including inclining block rates—can be considered time-based when coupled with a time-based modification (see right).

TOU — A time-of-use (TOU) structure reflects historical temporal variation in system costs by differentiating prices by time of day. Both prices and their applicable time period are predetermined.

RTP — A real-time pricing (RTP) structure provides prices that vary over short intervals (e.g., hourly) to closely (or exactly) reflect actual costs. Prices are not predetermined.

MODIFICATION OPTIONS

These mechanisms can be added to a base structure to increase rate sophistication without moving to a more complex base structure

+CP — Critical peak (CP) mechanisms charge customers higher prices or provide a rebate for a limited number of days each year, when system costs are highest.* The price is predetermined, as are the allowable time periods, but the actual peak events are finalized a few hours to a day in advance.

+VP — Variable peak (VP) mechanisms apply variable pricing or rebates to peak periods.** In VP, the peak periods are predetermined but the price can vary, for example, according to wholesale prices or reliability needs.

+FD — A flexible duration (FD) mechanism can be added to a CP or VP program, and uses peak periods that are not predetermined—this is intended to create a closer match between the actual timing of peak system costs and the signal sent to customers.

Demand Charges

A number of utilities propose to institute or expand demand charge programs for mass-market residential and small commercial customers, although very few demand charges have been approved for broad implementation due to questions about customer fairness and their effectiveness. Proponents of demand charges make many arguments for their expanded use, including that these rates could help with cost recovery and send price signals to better reflect cost causation. Opponents, on the other hand, make arguments including that demand charges limit the incentive for DERs including energy efficiency, rooftop solar, and electric vehicle charging, and

[3] These and other rate design considerations are described more fully in RMI's *A Review of Alternative Rate Designs: Industry Experience with Time-Based and Demand Charge Rates for Mass-Market Customers*. Available at https://www.rmi.org/insights/reports/review-alternative-rate-designs/. Unless specified, the figures and tables in this section are adapted from that report.

that demand charges are confusing to customers and highly punitive for occasional spikes in a customer's demand (which may not coincide with nor impact system-level costs).

One critical dimension of any demand charge rate is the peak coincidence, or the timing at which the customer's peak demand is measured to either coincide or not coincide with aggregate loading on the distribution or bulk system. Coincidence of demand charges can be assessed based on the following options:

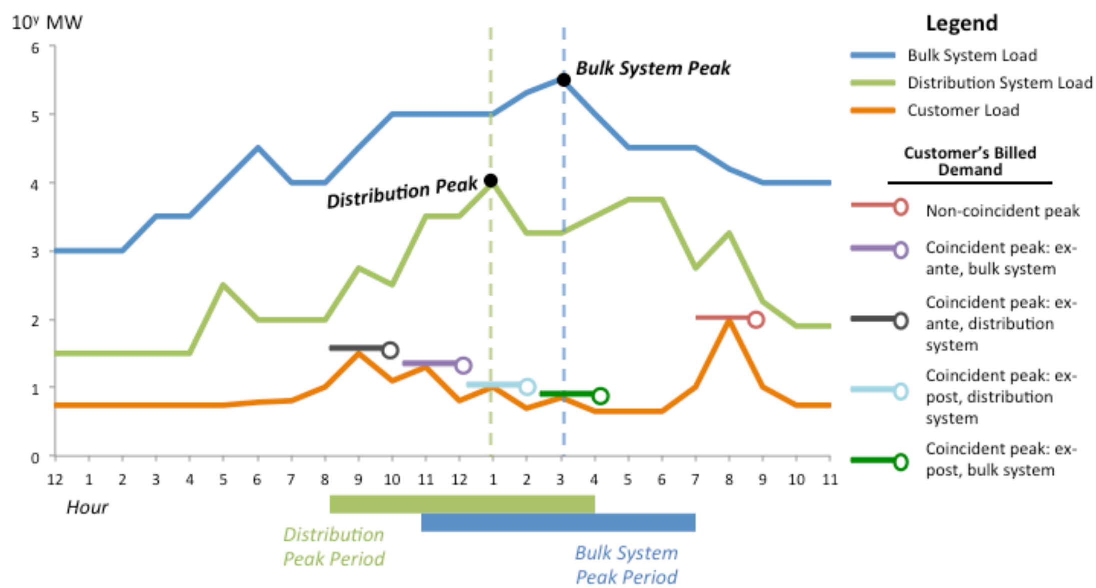
- **Noncoincident peak.** The customers' maximum demand at any time during a billing period (e.g., at any hour over a full month).
- **Coincident peak.** The customer's demand as measured during a specified time period that is determined to be at the same time as peak demand for a given level of the system (commonly either distribution system or bulk system).

Depending on when the timing of peak load is established, coincident peak demand charges can be:

- **Ex ante,** which are applied against the customer's demand during a predetermined peak period; or
- **Ex post,** which are applied against the customer's demand at the time when system peak actually occurs (the applicable measurement period is not known with certainty in advance).

The determination of noncoincident versus coincident peak measurement, as well as the definition of how and when peak will be measured, has significant impact on the assessed costs borne by customers. These design decisions also determine if the demand charge is actually assessed against those costs that they are claimed to recover. Figure 2 illustrates the potentially significant differences in measured peak demand for a customer depending on demand charge structure, as compared to actual peaks.

FIGURE 2: ILLUSTRATIVE EFFECT OF PEAK COINCIDENCE ON MEASURED CUSTOMER PEAK LOAD



Experience with mass-market demand charges is very limited compared to time-based rates (as of 2016, 15 states have utilities that offer demand charges, compared to time-based rates in nearly every state).[4] Where they exist, most residential demand charges in the US base charges on the customer's noncoincident peak, while others base it on an ex ante coincident peak.[5] Ex post coincident-peak demand charges have been applied to large commercial and industrial customers, but have not been used for mass-market customers. Noncoincident-

4 RMI (2016).

5 R. Hledik, "The Top 10 Questions about Demand Charges," presented at the EUCI Residential Demand Charges Summit, Denver, CO, May 2015.

peak demand charges may be more straightforward for customers to understand and for utilities to administer than coincident-peak demand charges but, if applied to anything beyond customer-specific costs (e.g., each customer's service drop and a share of the line transformer), they may not reflect cost causation.[6]

As seen in Figure 2, noncoincident demand charges risk imposing high costs on customers who are not associated with system peak (whether bulk system or distribution peak). Coincident peak demand charges are more likely to align with peak conditions on the grid; however, even these can be assessed at times that are far removed from the system conditions that they are supposedly intended to address. Cases such as this (which while illustrative are not uncommon) illustrate challenges with demand charges, including possible confusion to customers and risks of highly punitive costs resulting from singular demand events that may not even be associated with costly hours for grid operations.

In theory, it might be possible to achieve similar objectives using either time-based rates or demand charges, including peak demand reduction and better cost recovery. However, due to a lack of industry experience, those arguments remain largely speculative. RMI's *A Review of Alternative Rate Designs* describes common demand charge structures and reviews industry experience with these rates, finding that experience is limited and there is a lack of empirical studies to support their widespread adoption.[7]

In practice, demand charge proposals are often motivated more by a desire to ensure revenue certainty than to improve grid management or support customers' ability to manage their bill. Based on the discussion above, especially if the demand charges are based on noncoincident peak, it is hard to justify the cost causation claim. Instead, time-varying rates can accomplish similar objectives without putting customers at risk of highly punitive bills for a single high-usage moment that may not actually be a driver of system costs. These findings are further described in the Regulatory Assistance Project's PowerForward report to the PUCO.[8]

In light of their stronger track record and ability to serve broader objectives, we focus on time-based rates in this memo with less attention to demand charges.

DER Compensation: Beyond Net Metering to Value of Service

Due to rapidly declining costs of solar photovoltaics (PV) and other distributed energy resources, as well as increasing attention to clean energy and customer choice, traditional approaches to rate design are being further reevaluated to now encompass compensation for grid services. Net metering is one proven approach to catalyze market growth for solar PV, particularly in areas with low to moderate DER penetration.

Distributed solar and associated DERs have many demonstrated benefits to customers and the grid. A nonexhaustive list includes:

- Reduced energy bills for customers
- Reduced bulk system energy and capacity purchase requirements
- Lower system losses as less energy is transported long distances
- Opportunities for T&D asset deferral from targeted load management
- Environmental benefits including greenhouse gas abatement

Numerous "value of solar" studies have been conducted, with calculated value (benefits minus costs) ranging from levels somewhat below prevailing retail price to levels well above.[9] The range in calculated value is attributable to different geographic and system contexts, choice of input assumptions, and methodologies.

---

[6] J. Lazar and W. Gonzalez, "Smart Rate Design for a Smart Future," Regulatory Assistance Project, July 2015.
[7] RMI (2016).
[8] Regulatory Assistance Project (February 2018). "Recommendations for Ohio's Power Forward Inquiry."
[9] For one sample of studies, see RMI (2013), "A Review of Solar PV Benefit and Cost Studies."

In areas with higher DER penetration, attention has shifted to develop “net metering successor” structures that more accurately reflect underlying services and value. For example, Hawaii has moved beyond net metering to compensation at new “smart export” and “customer grid-supply plus” (CGS+) prices, and the state is beginning to develop a more complete menu of rate and program options that can be assembled according to customer preferences and capabilities (including demand response programs for ancillary services). New York’s Value of DER (VDER) proceeding, meanwhile, is updating pricing mechanisms to reflect time and locational attributes of distributed generation and other DER resources. Hawaii and other states are also considering payments to solar and DER customers for services provided by advanced inverters, including inverters’ support for voltage regulation on distribution systems—recognizing an opportunity to compensate customers for these services rather than necessitate utility investment in grid-sited assets.

Given that Ohio is currently at relatively low solar penetrations, it may be premature for the state to undertake major reforms to distributed generation compensation structures. At this stage, standard net metering structures are helpful to build an asset base and provide more certainty to the DER marketplace without imposing significant technical or economic impact on the system. As reported by Lawrence Berkeley National Laboratory researchers, “For the vast majority of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future.” LBNL further finds that, at current levels of distributed solar, net metering is not expected to impose more than 0.03 cents/kWh increase in retail prices, and any impact will remain fractions of a penny even after projected growth in distributed solar through 2030.[10] These are not the levels of purported cost shift that suggest a crisis requiring immediate reductions in compensation for customer-sited solar, especially in states with low solar penetration.

Meanwhile, improvements to more fundamental electricity rates, as well as other grid modernization investments and decisions, can set the stage for future development of DER programs that unlock significant value for customers and the grid. For example, Sunrun, a national residential solar installer, suggests that time-of-use rates are compatible with rooftop solar and can encourage installations that align with system costs while providing a stable price signal to customers.[11]

The bulk of this memo is focused on those underlying rate structures, including dynamic pricing and time-of-use rates as identified for attention in PowerForward by the PUCO.

III. NEW BEST PRACTICE FOR RATE DESIGN

Establish Objectives, Then Do Rate Design

Whereas in the past, utility rates sought to provide cost recovery and a reasonable return on utilities’ approved expenses, with some attention to fairness between customer classes, an expanded set of objectives are often now applied to rates. This reflects the increased centrality of electricity to economic and social activities, recognition of unpriced externalities associated with electricity, and changing economics and market structures available for power supply.

The following is a partial list of objectives commonly applied to rate design:

- **Customer choice** in available pricing plans and technology options
- **Affordability**, especially for vulnerable populations
- **Enabling innovation** by both utilities and third-party providers
- **Demand management** to support grid reliability and cost control

---

[10] Barbose, Galen. Lawrence Berkeley National Laboratory (2017). “Putting the Potential Rate Impacts of Distributed Solar into Context.”

[11] Sunrun (2018). “Affordable, Clean, Reliable Energy: A Better System Created by the People, for the People.” Available at https://www.sunrun.com/sites/default/files/affordable-clean-reliable-energy.pdf.

- **Environmental performance** including greenhouse gas reduction
- **Economic efficiency** in short-term pricing as well as long-run investment decisions

In a modern, multi-objective context in which different stakeholders have competing priorities, and in some cases different interpretations of what each objective should mean, regulators have an important role in establishing guidance for what they seek to achieve through rate design. Regulators can also provide criteria by which rate proposals will be measured. In cases where regulators issued expectations and guidance for rate design, subsequent stakeholder input and utility proposals have been stronger, in which more specific and robust input led to accelerated progress on reforms.

PowerForward provides a valuable forum to establish priorities and guidance that can orient stakeholders on how to proceed on rate reform. To make progress after the current exploratory phase of PowerForward, the PUCO should take account of the needs and opportunity in Ohio and then issue expanded guidance to direct the next phases of work and rate cases.

Nuanced Design Decisions Matter Greatly

In addition to expanded expectations for our electricity supply, new capabilities and needs have forced a reevaluation of how rates are set and implemented, including how best to recover various costs and what relationship customers should have with the grid. Alternative rate structures hold promise to better align prices with system needs. However, poorly designed alternative rates can be regressive and fail against program objectives.

RMI evaluates volumetric electricity rates according to three areas and nine dimensions (Table 1). All current and proposed rate structures should be considered through an assessment of how they apply these dimensions and what implications those will have on the customer user experience and consumption patterns.[12]

TABLE 1: DESIGN CHOICES FOR TIME-BASED RATES

Pricing Foundation	Structure	Implementation
1) Cost Components & Allocation What are the specific costs recovered through the rate, and how are they allocated?	**1) Peak/Off-Peak Price Ratio** What is the ratio of the price charged for peak-period consumption to that charged for off-peak consumption?	**1) Enrollment Method** What strategy is used to enroll customers in the rate design program (e.g., opt-in or opt-out)?
	2) Peak-Period Duration What is the timing and length of the period(s) where consumption is billed at a higher rate?	**2) Enabling Technology** What hardware and/or software are included to provide actionable information on consumption or prices, or automatically control load in response to price signals?
	3) Peak-Period Frequency How often do the peak time periods occur?	
	4) Number of Pricing Periods How many intraday time periods have distinct pricing levels?	
	5) Seasonal Differentiation	

[12] The design choices for demand charge rates are not included in this memo, but can be found in the RMI (2016) report *A Review of Alternative Rate Designs*.

	How many seasons (i.e., sets of months) have distinct rates?	
	6) Financial Mechanism Does the rate use a price or rebate to communicate to customers the cost/benefit of consumption at a given time?	

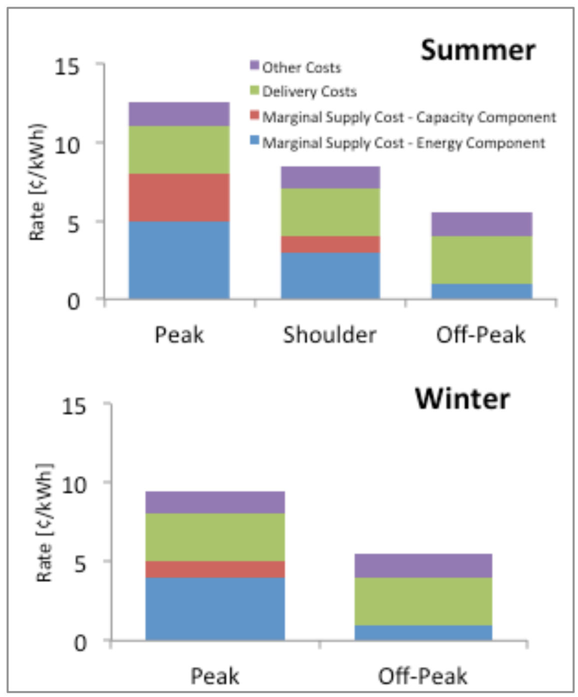
While all are important, a few dimensions require particular attention in the context of PowerForward and deliberations regarding possible rate reforms in Ohio.

Cost Components and Allocation

Cost allocation has always been a staple of utility rate design, but has historically focused predominantly on allocation of costs between rate classes (residential vs. commercial vs. industrial). Costs within rate classes, particularly for mass-market residential and small commercial customers, have traditionally been blended into a static volumetric ($/kWh) price. Increasingly, attention is given to allocation of different cost components between time periods (including winter vs. summer vs. shoulder seasons, and on-peak vs. off-peak hours).[13]

Figure 3 provides an illustrative depiction of how TOU cost allocation can break down between underlying energy, capacity, delivery, and other costs. Overall, supply (energy and capacity) cost is allocated largely toward peak and shoulder periods, whereas delivery costs remain little changed across periods. This structure is seen in the TOU rate by AEP Ohio, discussed below.

FIGURE 3: ILLUSTRATIVE TOU COST ALLOCATION



Note that these cost components are not necessarily associated with the same “on-peak” hours (i.e., on-peak generation costs might tend to occur in the afternoon, whereas a residential distribution circuit could experience evening peaks). That said, it is not necessarily productive to seek to precisely match every cost component with on-peak/off-peak time periods if doing so will not provide a practical signal to customers as to when to reduce usage in order to lower system costs. It is important to keep in mind that customers will generally perceive price signals in terms of the total bill, rather than through isolated components such as base rates, single cost components, or individual riders.

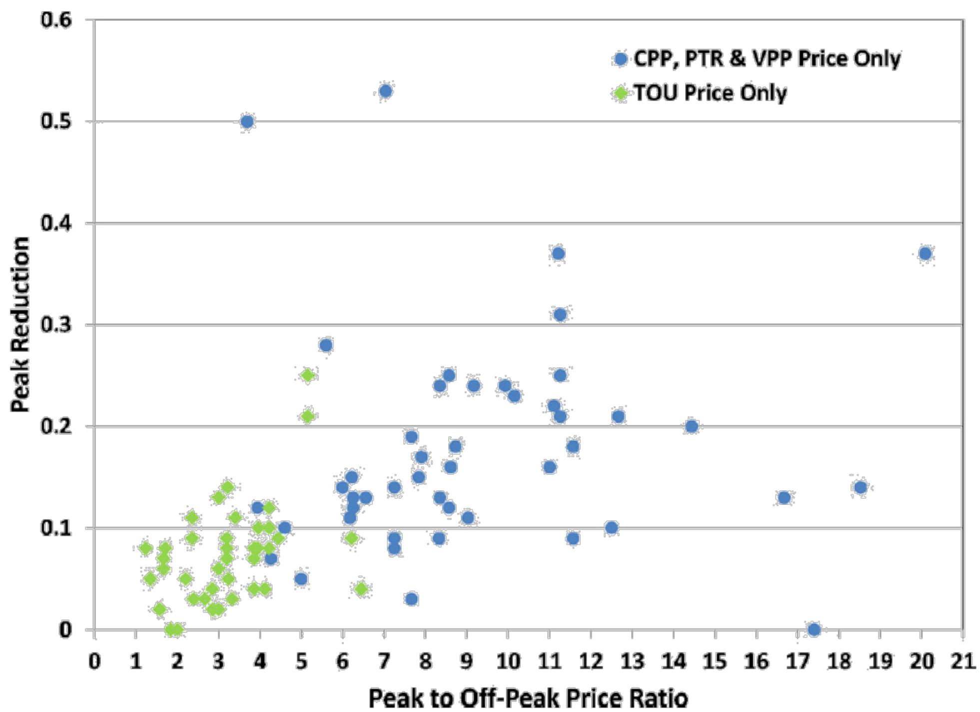
Peak to Off-Peak Price Ratio

The peak to off-peak price (POPP) ratio is one of the most important dimensions for time-based rates and provides a simple metric by which to quickly assess the rate. Higher ratios tend to elicit stronger customer response, particularly to achieve load shifting out of peak hours, while low ratios (less than 2:1) may not achieve desired results. Figure 4, from the Brattle Group, illustrates this

[13] A review of the full process of determining cost allocation among customer classes and the subsequent calculation of rates can be found in the following two articles: J. Lazar and W. Gonzalez, “Smart Rate Design for a Smart Future,” Regulatory Assistance Project, Jul. 2015; J. Lazar, “Cost Elements and Study Organization for Embedded Cost of Service Analysis,” Regulatory Assistance Project, Jul. 1992.

based on empirical data from time-based rate programs around the world.[14] As shown, modifications added to flat or TOU base structures (critical peak pricing, peak time rebates, or variable peak pricing) often have higher POPP ratios and therefore produce greater peak reduction, including in targeted hours.

FIGURE 4: PEAK-REDUCTION IMPACT BY POPP RATIO

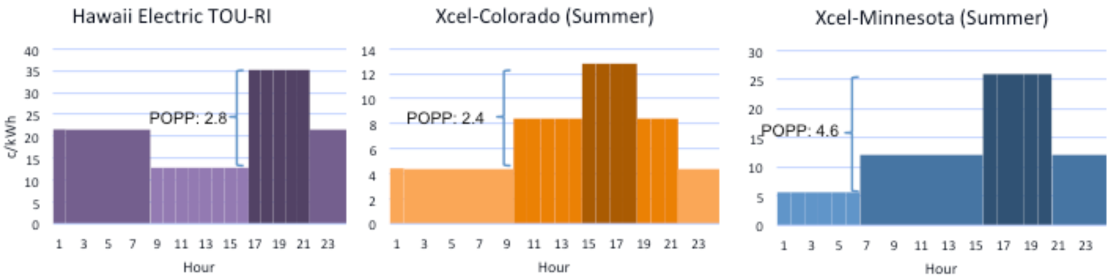


The POPP ratio is directly linked to other design dimensions, including peak period duration; longer on-peak periods tend to reduce the ratio, while short durations (2–4 hours on-peak) concentrate cost allocation in a smaller window and produce higher ratios. A common mistake is to design on-peak periods for customer rates that mimic bulk system on-peak hours (for example, weekdays from 7 a.m. to 11 p.m. in PJM, resulting in the majority of the day being "on peak"). This can lead to TOU rates with POPP ratios of nearly 1:1, making an imperceptible price difference that customers do not pay attention to.

In recent years, leading utilities around the US have developed TOU rates that apply some best practice to rate design structures, including concentrating on-peak prices in a limited set of hours to produce more meaningful price differences that better motivate customer response. Figure 5 shows some TOU rate structures being offered by Hawaiian Electric Company and Xcel Energy in Colorado and Minnesota.

[14] A. Faruqui and S. Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, vol. 26, no. 7, pp. 55–65, Aug. 2013.

FIGURE 5: TIME-OF-USE RATE STRUCTURES OFFERED IN HAWAII, COLORADO, AND MINNESOTA[15]



	HECO	Xcel-CO		Xcel-MN	
		Summer	Winter	Summer	Winter
Peak to Off-Peak Price Ratio	2.8	2.4	1.7	4.6	2.1
Peak to Shoulder Ratio	1.7	1.43	1.36	3.9	1.8

Implementation

While alternative rate structures need attention to pricing foundations and structure, they will ultimately fail if thoughtful and concerted attention is not given to implementation. Experience has shown the following:

- **Enrollment mechanism.** Most alternative rate programs enroll customers on an opt-in basis, however opt-out structures tend to result in greater impact with little difference in customer retention.
- **Customer education** is essential to help customers make informed decisions and mitigate adverse impacts. Education requires sustained efforts to overcome status quo bias and the tendency for overlooked communications, and it needs to be built on strong rate design fundamentals (i.e., underlying rates should be easy to understand and not impose undue cost risks on customers).
- **Information Technology** coupled with insights from behavioral economics supports effective customer engagement. Active technology (e.g., devices such as smart thermostats that automatically modulate customer load based on presets or programmed "strike prices") tends to be more effective than passive technology (devices that display signals but require human intervention to take action).
- **Shadow billing** is a tool that allows customers to monitor how costs may change under alternative rate structures before enrolling and can be considered as a program requirement to provide customer protection.
- **Online bill calculators** can similarly provide customers a simple tool to compare likely costs from available rate structures based on their historical meter data and could be required for utilities to offer.

Baltimore Gas & Electric (BGE) provides one example of a good customer education program. BGE's residential peak time rebate (PTR) program (called "Smart Energy Rewards" or SER) enrolled over 1 million customers as of 2016.[16] BGE uses multiple channels to educate and inform customers, including sending event notification through phone calls, text messages, emails, or paper, and provides immediate customer feedback with personalized information after the event.

Third-party service providers, including Oracle (formerly OPower), Simple Energy, and Tendril, have also pioneered a range of implementation and program management structures for alternative rate and load management programs that can support effective program implementation. Utility partnerships with these or other companies are helpful to apply best practice for program design and introduce added expertise into utility

[15] Data source: Utility tariff sheets.

[16] https://blog.aee.net/the-state-of-advanced-metering-infrastructure-and-time-varying-rates-in-three-maps-and-one-graph.-the-leaders-and-laggards-may-surprise-you

and regulatory design processes. BGE partners with OPower, for example, to provide reports to customers with personalized energy saving tips based on their PTR behaviors. This has contributed to high customer participation and satisfaction.[17]

In addition, well-designed pilot programs can support implementation of alternative rates in a manner that allows utilities to gain valuable experience with new price structures and to understand customer response. RMI research on effective pilot and demonstration projects finds the following best practices:[18]

- **Strategic Planning:** Both regulators and utilities should set clear targets and convey consistent messaging around their strategic priorities.
- **Design to Scale:** In presenting any pilot for regulatory approval, utilities should be able to articulate a plan for how the pilot supports possible scaling in the future (pilots should not be one-time experiments that are later abandoned).
- **Organizational Leadership:** Regulators, utilities, and third-party service providers should institute leadership support and dedicated resources to ensure effective innovation and to make sure that lessons are recorded and impact sticks.
- **Stakeholder Engagement:** Utilities, technology provides, regulators, and customers should all engage collaboratively from the beginning to build common ground and shared expectations for the pilot. (Although it requires up-front time and cost, pilots are better with more stakeholder input.)

IV. RATE DESIGN IN OHIO: OBSERVATIONS AND OPPORTUNITIES FOR IMPROVEMENT

Summary Observations and Takeaways

Electric distribution utilities (EDUs) in Ohio set distribution rates for all customers as well as generation rates for customers who have remained with their utility as the default service provider. We evaluated the mass-market customer TOU programs offered by Cleveland Electric Illuminating Company, AEP Ohio, and Duke Energy using the framework described above. Dayton Power & Light is not included because the utility does not offer a TOU program for mass-market customers.

We mainly consider the rates from the customer perspective, which is the total rate including generation, transmission, and distribution rates. For the AEP example, we break down the rate into different components, but it is important to be aware that the design choices and best practice discussed above should be viewed from the perspective of considering the total rate.

We make the following general observations based on this review:

- There is room for improved design and implementation in all time-based rate programs, including instituting higher POPP ratios in most cases.
- Many programs have low customer enrollment and have caused adverse bill impacts to customers.
- Better customer education and use of enabling technology could improve the adoption and bill management for existing programs, and are essential for new or more-advanced dynamic rates.
- Across Ohio EDUs, current distribution rates have limited (or no) variation across TOU time periods (as compared to generation rates that vary significantly across periods). This might change given the need to recover distribution grid modernization costs, but also has important implications for consideration to transferring provision of TOU programs to CRES providers (discussed in the next section).

---

[17] https://www.edf.org/sites/default/files/content/harbaugh_presentation.pdf

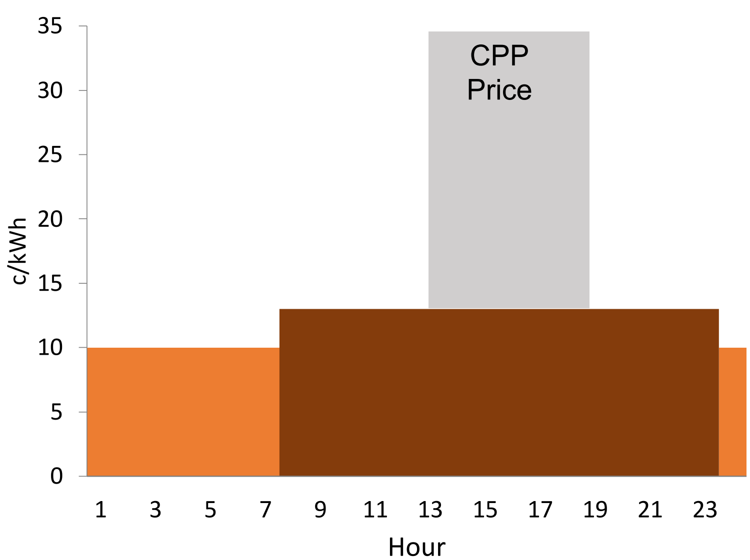
[18] RMI (2017). "Pathways for Innovation: The Role of Pilots and Demonstrations in Reinventing the Utility Business Model." Available at https://www.rmi.org/insights/reports/pathwaysforinnovation/.

- Existing electricity infrastructure in Ohio, including advanced metering infrastructure, is not currently capable of unleashing the full value of advanced rate structures. Enabling technologies, including smart devices and advanced demand management systems, need to be coupled with two-way communication systems and appropriate data exchange protocols to help this market grow.

FirstEnergy and Cleveland Electric

Cleveland Electric Illuminating Company (Cleveland Electric) is one of three operating companies of FirstEnergy in Ohio.[19] Cleveland Electric offers TOU programs for residential and small commercial customers. Commercial customers have three-period TOU rates applicable throughout the year, while for residential customers, time differentiation is only in the summer. Residential customers can also opt into a critical peak pricing (CPP) program, in which CPP events occur up to 15 days per year. The peak period runs from 7 a.m.–11 p.m. in the summer—very long at 16 hours, not giving customers much flexibility to shift their load to off-peak hours. In addition, the residential POPP ratio is only 1.3 for the daily TOU structure, which does not create a strong incentive for customers to change consumption patterns given little price difference between periods. The ratio of 3.6 for the CPP program is better, although still relatively low as compared to CPP programs that are found to elicit significant load response.

FIGURE 6: CLEVELAND ELECTRIC'S EXPERIMENTAL RESIDENTIAL CRITICAL PEAK PRICING PROGRAM (SUMMER)



TOU Peak to Off-Peak Price Ratio	1.3
CPP Peak to Off-Peak Price Ratio	3.6

While Cleveland Electric's TOU program is underwhelming, there is evidence for more load management opportunity from a modified time-based rate structure. FirstEnergy worked with the Electric Power Research Institute (EPRI) in 2013 to evaluate the impact of peak time rebate (PTR) programs among FirstEnergy territories in Ohio. The study showed that customers who received a programmable communicating thermostat (PCT) and allowed the utility to control the thermostat on called peak-day events showed 75% higher demand reduction for electricity than those customers who reduced demand on their own initiative. Customers who only received

[19] The other FirstEnergy companies in Ohio are Ohio Edison Company and Toledo Edison Company.

passive in-home displays (IHDs) showed the lowest demand reduction on event days, demonstrating the relative value of active technologies over passive.[20]

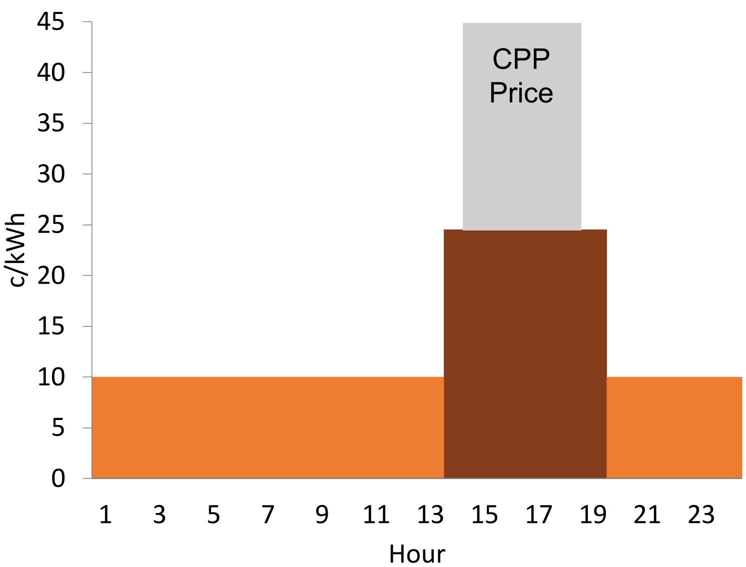
This could have implications for utilities and regulators when they are considering rate programs that require even greater behavioral changes, up to and including real-time pricing. For example, simply sending prices through passive in-home displays or smart phones might not achieve response at the scale desired, and instead could impose significant bill volatility and customer frustration. In this case, utilities and regulators need to consider better customer education coupled with program rollout to help customers understand the economic benefit they could achieve by adjusting energy use patterns or, to be more effective, should employ more active technologies like grid-interactive water heaters and smart thermostats that can "learn" and respond to price signals to reduce load during peak periods.

After the 2013 pilot, PUCO staff suggested that FirstEnergy should offer a TOU plus CPP rate to customers in Phase 2 of the program and evaluate resulting impacts.[21] The evaluation result is not yet public; additional information is needed to compare the monetary and energy savings of Cleveland Electric's price-based and rebate programs.

AEP Ohio

AEP offers opt-in TOU rate options for residential and commercial customers. Both residential and commercial programs have a two-period price structure that applies the on-peak pricing hours only during summer months. The on-peak period lasts 6 hours (1 p.m.–7 p.m.) for both programs. The residential TOU program has a POPP ratio of 2.5, while the commercial program has a ratio of 3.2. AEP also operates a residential critical peak price program that can be called up to 15 days a year, with a POPP ratio of 4.5 for CPP events—a stronger price signal than the daily TOU structure, however, relatively low for CPP.

FIGURE 7: AEP'S EXPERIMENTAL RESIDENTIAL TIME-OF-DAY AND CRITICAL PEAK PRICING PROGRAM (SUMMER)[22]



TOU Peak to Off-Peak Price Ratio	2.5
CPP Peak to Off-Peak Price Ratio	4.5

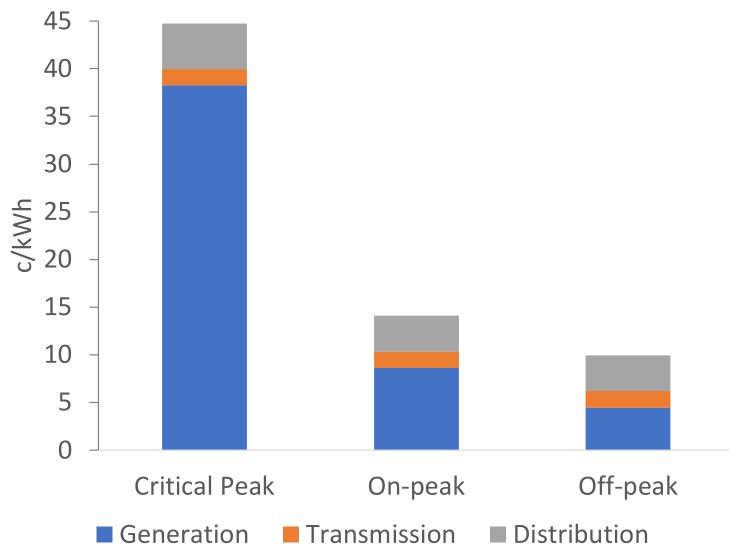
[20] EPRI, FirstEnergy's Smart Grid Investment Grant Consumer Behavior Study Phase 1: Final Evaluation, June 2015.

[21] PUCO Staff report on Case Numbers 09-1820-EL-ATA, 09-1821-EL-GRD, 09-1822-EL-EEC and 09-1823-EL-AAM, February 8, 2013.

[22] Data Source: Ohio Power Company - Columbus Southern Power Rate Zone Tariff Sheet and Bill Calculation Spreadsheet, available at: https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx.

Figure 8 illustrates the breakdown for AEP's current residential TOU program. Price differentiation is contained entirely in the generation portion of the rate, whereas distribution costs are the same between on-peak and off-peak periods. The generation portion varies significantly between the two periods, dominating the on-peak rate at 78% of total cost. This suggests opportunity to introduce more price difference on the T&D portion of the rate to align price signals with periods in which peak system costs are associated. However, the figure also illustrates the relatively small portion of costs attributed to T&D, and hence less margin for meaningful adjustment to these rates if generation pricing is removed from utility provision.

FIGURE 8: BREAKDOWN OF VARIABLE CHARGES FOR AEP ON-PEAK AND OFF-PEAK PERIODS[23]



Duke Energy Ohio

Duke Energy offers a TOU rate for residential customers but does not have a comparable program for commercial customers. Participation and bill impact data show that the residential program has underperformed. As of June 2017, only 18 customers were enrolled on the TOU rate and all would have a lower bill if they switched to the standard rate.[24] This low program performance may be attributed to a number of factors, including rate design details or lack of effective marketing and implementation measures, although the rate structure itself has some attractive features. The summer POPP ratio of 4 is relatively high and therefore expected to influence customer consumption patterns. The peak period duration, on the other hand, is fairly long at nine hours in the summer (11 a.m.–8 p.m.),[25] which could present challenges for customers to shift load without undue burden. Notably, Duke previously offered a CPP program for residential customers but cancelled it. A well-designed CPP program could better target hours of system need, encouraging peak demand management when needed most.

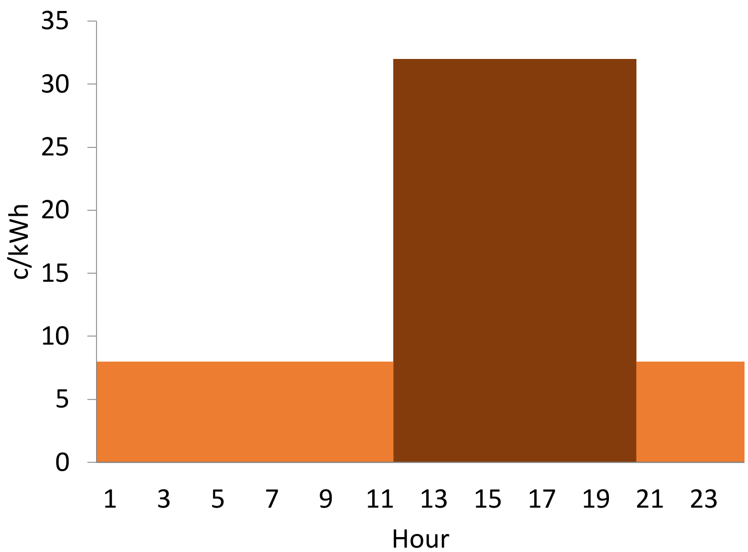
---

[23] Generation rate includes: Generation Energy Rider+Generation Capacity Rider+Alternative Energy Rider+Auction Cost Reconciliation Rider; Transmission rate includes Basic Transmission Cost Rider;
Distribution rate includes: Distribution Energy Charges+kWh Tax+Pilot Throughput Balancing Adjustment Rider+Energy Efficiency and Peak Demand Reduction Cost Recovery+Significant Excess Earning Test Credit Rider.

[24] PUCO Staff Data Requests, Case No. 17-0032-EL-AIR, April 11, 2017.

[25] Duke's residential TOU program has a POPP ratio of 3.6 in the winter, with two on-peak periods (9 a.m.–2 p.m. and 5 p.m.–9 p.m.).

FIGURE 9: DUKE ENERGY'S RESIDENTIAL OPTIONAL TIME-OF-DAY PROGRAM (SUMMER)



TOU Peak to Off-Peak Price Ratio	4

V. RETAIL CHOICE AND EXPANDED COMPETITIVE SUPPLY

As Ohio utilities deploy smart-meter technology that can facilitate more innovative rate structures, there is opportunity for CRES providers to take a greater role in providing time-varying rates through the competitive market. As this transition proceeds, the utilities would continue to provide delivery service to customers and set corresponding distribution rates but have a reduced role in generation rates as CRES providers set those. As we understand the decisions under consideration, it is an open question whether utilities would continue to offer time-varying options as default service providers.

Although expanded competitive supply holds promise for greater customer choice and innovation, it is important that the PUCO and regulated utilities maintain its role in ensuring that customers have quality, affordable rate options for their electricity supply. In particular, Ohio's EDUs are an important vehicle for developing alternative rate structures that promote affordability, DER integration, and grid stability.

Based on RMI's research of competitive supply in other jurisdictions and our understanding of the Ohio situation, we summarize the following takeaways for the PUCO:

- Industry has seen both opportunities and risks of expanding competitive retail supply with respect to rate offerings. Regulatory actions for customer education and protection could reduce confusion, but downside risks are difficult to impossible to eliminate completely.
- In Ohio, the PUCO should encourage or require regulated utilities to design well-functioning TOU programs, which can also serve as a motivating baseline for CRES providers to improve upon.
- Currently, the generation rate is the major driver of the price difference between TOU periods. This suggests that the PUCO risks neglecting a large share of total energy cost if CRES providers are the exclusive providers of TOU rates, leaving default service customers with no TOU rate option.

Lessons from Other States

Experience in other states with retail choice illustrates these opportunities as well as concerns, and points to important regulatory controls and market design decisions. Even under the best market design and customer protections, however, risks of customer confusion and potential for bill increases are likely to persist due to the inherent complexity of electricity rates combined with the limited attention that most customers give to utility bills.

New York provides a cautionary tale on expanded retail choice, particularly for adverse bill impacts to low-income populations. Following deregulation in the 1990s, the New York Public Service Commission (NYPSC) promoted a policy to move customers to competitive providers (known as energy service companies, or ESCOs, in New York). Following aggressive marketing practices and ratemaking changes to encourage incumbent utilities to promote switching to ESCOs, large numbers of mass-market customers migrated to these suppliers. As of February 2014, 214 ESCOs were eligible to provide electricity in New York State, serving approximately 24% of residential customers and 35% of small commercial customers.[26]

Long-standing criticisms of New York ESCOs came to a head in recent years, in part related to the Reforming the Energy Vision (REV) initiative, in which ESCOs were seen as a vehicle for innovation in service offerings, including development of new customer-oriented products in a "platform" marketplace. Based on a NY Department of Public Service investigation into the 30 months ended June 30, 2016, low-income customers supplied by ESCOs paid almost $96 million more than the residential customers who elected to take supply from their utility for the same period.[27] Following significant press attention and investigation of these practices, the NYPSC ordered that service and rate design responsibilities for low-income customers be transferred from ESCOs back to utilities.[28] This action resulted in lawsuits disputing the NYPSC's oversight authority of ESCOs. In September 2017, a New York State appellate court upheld the commission decision, finding that state regulators have a statutory responsibility to protect customers.[29]

The ERCOT market in Texas offers a more mixed case on both the opportunities and risks of competitive retail choice. Commonly pointed to as the model of complete restructuring toward competitive retail competition, customers in the ERCOT footprint are served by retail energy providers (REPs), while utilities manage the distribution network.[30] REPs are subject to regulated tariffs and rates paid to distribution utilities for each customer they serve. Those rate structures vary by customer class, but for residential customers include customer and metering charges (per customer) as well as transmission and distribution charges (per kWh), and an additional "transmission cost recovery factor" (also per kWh). While REPs must pay those rates to the

---

[26] Cases 12-M-0476 et al., Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State, Order Taking Actions to Improve the Residential and Small Non-Residential Retail Access Markets, Issued February 25, 2014.

[27] Cases 12-M-0476 et al., Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State, Press Release: ESCOs Banned from Selling to Low-Income Customers in New York: Investigation Finds Customers Overpaid ESCOs Hundreds of Millions of Dollars. Issued December 15, 2016. Available at: https://www3.dps.ny.gov/pscweb/webfileroom.nsf/Web/565828CCDE596E7B8525808A006F1803/$File/pr16085.pdf?OpenElement .

[28] Cases 12-M-0476 et al., Proceeding on Motion of the Commission to Assess Certain Aspects of the Residential and Small Non-Residential Retail Energy Markets in New York State, Order Regarding the Provision of Service to Low-Income Customers By Energy Service, Issued July 15, 2016; Order Adopting a Prohibition on Service to Low-Income Customers by Energy Service Companies, Issued December 16, 2016.

[29] Knauss, Tim. "After court victory, NY resumes ban on energy marketer sales to low-income customers." Syracuse.com; September 7, 2017. Available at http://www.syracuse.com/news/index.ssf/2017/09/after_court_victory_ny_resumes_ban_on_energy_marketer_sales_to_low-income_custom.html; accessed March 7, 2018.

[30] Texas customers outside of the ERCOT market boundary, as well as those served by municipal utilities or other public power providers, are not subject to the same retail choice market as ERCOT territories historically served by investor-owned utilities.

distribution utility, they have wide latitude in how to translate their costs to prices paid by customers, as well as how they set prices for generation. This has led to development of some novel pricing plans, such as the "free nights and weekends" concept.[31]

Some features of ERCOT rules and PUC of Texas regulations have helped promote a functional retail choice market, including:

- A "Power to Choose" website (similar to Ohio's "Apples to Apples" site) allows customers to compare available price plans,[32] providing, in theory, a service similar to what Kayak or Orbitz provide for travel costs comparisons.
- Extensive customer protections are in place to govern how REPs advertise and do business.[33]
- ERCOT serves as independent registrar and settlement agent for retail providers, reducing the potential for conflict of interest that would exist if the utilities served this function.
- REPs are subject to significant capital requirements to do business, ensuring they are legitimate companies and capable of weathering potentially very high price swings in the ERCOT market for energy.

Even so, retail choice in Texas is not without its critics and shortcomings:

- The "Power to Choose" website, and REP offerings more broadly, have been derided as "power to confuse" due to a tendency for providers to promote enticing prices on portions of electricity consumption, while including hidden fees and mechanisms that can unexpectedly ratchet up costs.[34]
- Efforts by regulators to update customer protections and ensure appropriate transparency of contract terms are undermined by some REPs' ability to find loopholes and always stay one step ahead of regulations.

Takeaways on CRES Expansion

Expansion of competitive retail supply of electricity—and commensurate contraction of utilities' roles—is a significant issue in electricity market design, which offers promising opportunities but also carries substantial risks that require attention.

Opportunities include:

- Lower electricity costs for customers resulting from competition between providers
- Innovation in pricing structures that create more customer choice and price plans that appeal to differentiated customer circumstances and energy use patterns (for example, "free nights and weekends")
- Innovation in service offerings to end-use customers based on customer preferences (such as clean energy supply, improved power quality, or rates combined with additional services such as energy efficiency or electric vehicle charging)

Risks include:

- Erosion of alignment between state policy and regulatory objectives with competitive providers' offerings that are not subject to the same oversight

---

[31] Examples of Free Nights program: https://www.acaciaenergy.com/electric-plans/pay-as-you-go-plans/free-nights/; Free Weekends program: https://www.directenergy.com/freeweekends.

[32] See http://www.powertochoose.org/

[33] See Chapter 25 of *Electric Substantive Rules*, "Substantive Rules Applicable to Electric Service Providers"; *Subchapter R. Customer Protection Rules for Retail Electric Service.* Available at http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/ch25complete.pdf.

[34] Holeywell, Ryan. "Some say electricity website has power to confuse: Critics say spot detailing electricity plans far too complex/" HoustonChronical.com, April 17, 2015. Available at https://www.houstonchronicle.com/business/energy/article/Some-say-electricity-website-has-power-to-confuse-6208091.php; accessed March 9, 2018.

- Potential for customers to pay more in total electricity costs than they would under default-provider rates, due to confusing price plans and contract terms
- Customer abuses resulting from misleading marketing practices and hidden fees
- “Innovation” limited to diversity in price plans without change in underlying generation mix or service options (i.e., sources of electricity are unchanged without meaningful product innovation, especially for small residential and commercial)

The experience in other states makes clear that expanded competitive supply is not a panacea to creating new customer and system value. Without appropriate oversight, customer protections, and foundational elements for market design, there is risk that competitive providers will fail to deliver cost savings and other customer benefits. By contrast, if done well, thoughtful design of retail choice markets can encourage new sources of value and innovation. In addition to the issues discussed above, those may include requirements for data sharing with third-party providers, fair interconnection practices, and establishing meaningful standards and review protocols to ensure adequate customer education and understanding.

Given the PUCO’s clear oversight authority over default service providers, EDUs provide an important vehicle to promote rate design best practice and support fulfillment of public policy objectives. Rather than shift provision of time-varying rates exclusively to CRES providers, the PUCO may consider maintaining (possibly requiring) this option for incumbent utilities as well, including for generation. Doing so would allow the commission to promote rate design best practice as described elsewhere in this memo and establish a minimum best practice that CRES providers would be motivated to improve upon.

VI. RECOMMENDED NEXT STEPS AND TIMELINE

PowerForward is occurring at an opportune time to institute electricity market reform in Ohio. Changes in technology costs and capabilities, as well as pressing economic and environmental needs, make reform critical to reposition the utility sector for twenty-first century services. At the same time, reforms undertaken elsewhere provide invaluable experience and lessons learned that Ohio can apply to make better and faster progress.

While the issues are complex and intertwined and it can be daunting to know where to begin, there are practical steps that the commission can take to make progress. PowerForward has provided a useful forum to explore issues, learn from experts from inside and outside Ohio, and better understand stakeholder positions. Now, the commission should take stock of what it has learned and promote targeted changes that enable utilities and other market actors to modernize their businesses in line with state policy goals.

A risk that many regulators around the US fall prey to is to let inertia prevail due to procedural bias to perpetually *explore, ask,* and *talk,* rather than move ahead in a learn-by-doing manner. This does not suggest immediate, sweeping reforms that may upset markets and impose undue costs on customers. Rather, there are useful, no-regrets actions that regulators can take to accelerate utility and grid modernization. Rate design is an essential foundation for broader power sector reforms, on which immediate work should begin to update rates and build experience toward electricity prices that better support a flexible, affordable grid.

The following are some steps that the PUCO may consider:

1. **Issue targeted guidance** that identifies commission expectations and objectives for rate design. Utilities and parties to rate design proceedings benefit from a clear understanding of what regulators seek from rates and what criteria will be used to evaluate rate proposals. When commissions establish clear objectives, suggested rate structures to consider, and specific procedural steps or milestones, subsequent activities and stakeholder discussions align behind those and can progress toward meaningful outcomes.

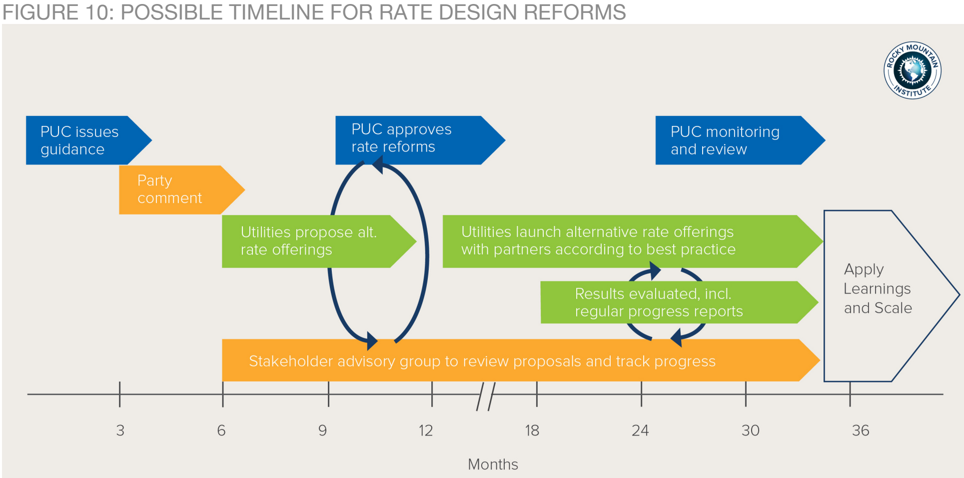
2. **Invest in resources and expertise** to ensure that the commission is equipped to appropriately evaluate and respond to proposals and other rate design developments. Under-resourced regulators face an enormous challenge to discern the meaning and implications of proposed changes, as the issues and market dynamics are more complex now than ever, and special interests introduce risk that policy changes may not reflect customers' and social interests. This issue is not unique to Ohio—regulators everywhere face new and complex questions that are beyond historical functions and areas of expertise. Commissions need to invest in education and build their ability to both understand and lead on rate design and other issues. Capacity and expertise can be built in a variety of ways, including recruitment and investments in internal regulatory staff, and seeking support from external experts who can serve public interest objectives aligned with the state.

3. **Require utilities to conduct pilots** for time-based rates that follow established best practice. Pilots or demonstration programs are an opportunity to experiment and move quickly to understand and refine program designs before scaling to broader application. The utility industry is notorious for conducting pilots with high expectations that are later deemed failures or wastes of ratepayer money. For rate design in particular, undersubscribed or poorly managed pilot rates may wrongly be pointed to as evidence of the folly of alternative rate structures, when in truth pilot shortcomings are often attributable to a combination of poor underlying rate structure, lack of attention to implementation, and static pilot design without built-in feedback for learning and refinement. Rate design pilots should apply best practice with respect to rate design dimensions as well as pilot design and scaling mechanisms. FirstEnergy's pilot in partnership with EPRI is encouraging; it will be important now to ensure that results are well-recorded and evaluated, then lessons applied and scaled appropriately.

4. **Evaluate the bill impact of new rate designs** to understand likely impact on customers. As utilities or other stakeholders propose new rates—both updated standard offer rates and alternative rate structures like time-of-use—the commission needs to understand cost and value impacts to a range of customers. This requires appropriate scenario development that includes multiple customer types (varied by demographic as well as load shapes) and evaluation of different customer response potentials (e.g., fixed consumption patterns vs. flexible load opportunities). Evaluation of likely bill impacts that feed back to appropriate adjustments to rates, combined with implementation tools like shadow billing and customer-oriented bill impact estimation tools, help to create rates that are user friendly and allow bill management by customers.

The following steps may be considered to guide actionable progress and modernize rate design in Ohio. These steps are also illustrated in Figure 10.

FIGURE 10: POSSIBLE TIMELINE FOR RATE DESIGN REFORMS



Immediate 3–6 months

- **PUCO issues guidance**, including stated objectives for rate design, suggested design elements to prioritize, and desired timeline for further development
- **Solicit feedback** from utilities and other parties on suggested approach
- **Refine guidance** (as appropriate) then direct utilities to propose path forward, to include innovative pilot programs for improved time-varying rate design with explicit guidance to apply identified best practice for:
    - Rate design structure and implementation strategies, and
    - Design of pilot programs to support learning and scaling.
- **Convene a stakeholder advisory group** to work with the PUCO and EDUs to give feedback and support future strategy development

Next 4–6 months

- **Each EDU develops rate design strategy** including approaches for default rates and proposals for innovative pilots; EDUs directed to include descriptions of:
    - How the strategy will achieve Commission's stated objectives,
    - Detailed plans for customer education and engagement, and
    - Key partnerships with third-party service providers.[35]
- **Commission review of proposed pilots** to approve or request improvements as appropriate

Next 2–3 years

- **EDUs implement rate reforms and pilots** with partners
- **Evaluate outcomes** through utility-filed reports, independent third-party assessments, and stakeholder dialogue; identify program successes and failures to learn from experience and determine focus for scaling
- **Apply lessons and scale** to more customers

There are, of course, alternative approaches and variations on this timeline depending on the State's objectives and level of ambition for dynamic rate structures. For example, California is in the process of migrating to default TOU rates for residential customers. Beginning with legislation and followed by a PUC-initiated "Residential Rate Redesign" proceeding in 2013 to evaluate options, the commission subsequently ordered utilities in 2015 to conduct opt-in TOU pilots in preparation for default TOU offerings beginning in 2019 (i.e., six years from procedural initiation to full implementation of default TOU rates, with studies and pilots along the way).[36]

Whatever the precise timeline, it is key to maintain high standards for application of best practice and emerging insights from across the industry at every step. Significant attention by utilities, stakeholders, and regulators alike is needed to ensure that rates do not revert to bad design and ineffective implementation measures. On the other hand, through collaborative approaches built upon clearly established regulatory and policy expectations, well-managed dynamic rate designs can support modern grid needs as well as increased customer choice.

[35] Experience can be drawn from the New York PSC approach (2015 to present) to require utilities to conduct "REV demos" in partnership with third parties.

[36] For details, see CPUC Decision 15-07-001 (July 3, 2015) and additional overview of the process by the CA Office of Ratepayer Advocates (http://www.ora.ca.gov/general.aspx?id=2444).

22830 Two Rivers Road
Basalt, Colorado 81621 USA
www.rmi.org