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Recommendations for Ohio's Power Forward Inquiry

Janine Migden-Ostrander, David Littell, Jessica Shipley, Camille Kadoch, Joni Sliger

Table of Contents

Disclaimer

This paper was prepared at the request of the Ohio Public Utilities Commission (the Commission). It is meant as informational, and the views and opinions expressed herein do not necessarily represent the views of the Commission.

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I. Executive Summary

Ohio's "Power Forward" inquiry is intended to examine options for modernizing the electricity grid and improving customer engagement, so that the Public Utilities Commission of Ohio can put forward-thinking policies in place. This report explores some of the technological and regulatory innovations that could help Ohio achieve this grid modernization, particularly within the framework of performance-based regulation (PBR) and alternative approaches to cost recovery and rate design.

The Commission's rate-making authority gives it the scope to put performance incentive metrics in place, including metrics that consider utility management practices, and to adjust utilities' rates of return based on these practices. When Ohio restructured its electric industry, the Legislature's articulated policy goals included the fostering of innovative service developments, transparent provision of market incentives, and encouragement to adopt energy efficiency measures and distributed generation. The Power Forward inquiry rests on this authority, and the Commission is on firm ground in considering performance incentives to modernize the grid.

Traditional "cost-of-service" regulation, where the rate of return is set on rate base, gives utilities incentives to invest in additional infrastructure to increase their own revenues, even when less expensive options are available to meet customers' needs. The adoption of distributed generation can raise tensions within a traditional cost of service system, because it is seen to reduce utilities' sales. PBR works around this tension, creating a framework in which utilities' compensation and returns are connected to service goals, targets, and measures. This enhances the grid, gives customers more options, and keeps the utilities financially viable while facilitating least-cost solutions.

Some jurisdictions have moved toward a comprehensive reworking of their regulatory models to put PBR in place; the United Kingdom's approach is a longstanding example. Others have sought to layer performance incentives onto an existing regulatory framework. Within Ohio's current system, the setting of performance incentives in the latter fashion can be a first step toward shifting utility behavior in the direction of grid modernization goals. Key to this process are the understanding of business-as-usual outcomes prior to setting incentives, so the utility does not receive additional revenue without corresponding customer benefit; transparency in the setting of incentives; and that the incentives be of sufficient size to motivate utility performance improvements.

Performance incentives such as shared savings have been used successfully for many years in Ohio and elsewhere in the United States to incentivize utilities to achieve specific energy efficiency criteria. These incentives can be expanded by combining them with multi-year rate plans (MRPs), allowing utilities to earn revenue even with lower sales. MRPs often feature a rate cap, which limits what the utility can charge customers, or a revenue cap, which limits how much revenue the utility can recover. To avoid the risk that the utility responds by reducing service quality rather than by increasing efficiency, performance metrics can be set to measure customer service, outages and responses, and other factors. MRPs can materially improve utility cost performance and therefore provide a promising strategy for addressing some challenges facing Ohio's utility industry. Complementary operational incentives can maintain and improve reliability and customer service through the most effective mix of operational and capital investment decisions.

Potential performance metrics to help Ohio achieve the grid modernization goals of the Power Forward inquiry may include:

- Improvements to utility reliability: Ohio's existing reliability standards and reporting requirements could be tightened, and the Commission could recognize a minimum threshold for performance above which utilities could excel.
- Improvements to safety: Safety metrics would include emergency response time and rates of worker accidents and injuries. The design of these should ensure that the utility does not have a disincentive to report on-the-job injuries.
- Improvements to efficiency: Ohio has utilized a shared net benefits approach that rewards percentage or kWh energy savings, and it has worked well. Such mechanisms should clearly identify the shared benefits, ensure the utility appropriately controls costs, and use a mechanism that cannot be gamed.
- Improvements to system/operational efficiency: Possible measures here include voltage optimization, peak reduction, and load factor improvement.
- Enhancements to the retail market: Utilities can set metrics for the level of access to data by third parties and customers, as well as targets for greater penetration of distributed energy resources. To send accurate price signals to customers, real-time rates, such as those piloted in Illinois, can be used.
- "Smart grid" goals: PBR can encourage the deployment of advanced metering infrastructure (AMI) and use it to allow customers to manage demand.

- Electric vehicle (EV) deployment: Tracking metrics for EVs can provide information about their adoption by customers and—if we think about EVs as "mobile batteries"—possible energy storage and system balancing benefits to the grid.

Several methods of alternative revenue compensation are possible in a PBR framework. One of the methods for providing incentives (and penalties) to utilities is through adjustments to the rate of return. Options here for efficiently setting utility revenue requirements include the "TOTEX" model, which combines capital expenditures (capex) and operating expenditures (opex) in a single cost parameter; treating certain types of expenses as capital expenses; or setting incentives below the value of the desired outcome/savings.

As end-use customers employ more technologies to save energy or generate their own, electric distribution companies are likely to lose more revenue. Various regulatory mechanisms to address this have come into use across the country:

- Straight fixed/variable (SFV) rates: In traditional rate designs, utilities recover fixed costs in a fixed charge and variable costs in the volumetric charge. An SFV rate changes this by inappropriately reclassifying variable costs as fixed costs. The risks here include that higher-use customers will pay relatively less while lower-use customers pay more.

- Demand charges: This rate design was traditionally used for commercial and industrial customers, and a major concern is that residential customers will not understand how to adjust their usage. Another problem is that residential usage peaks are not coincident to utility peaks.

- Decoupling of sales from revenues: This mechanism, which some Ohio utilities have implemented, is the only method that both addresses utility lost revenues and sends the appropriate price signals to customers by retaining the traditional volumetric portion of the rate. No two decoupling mechanisms are alike, and a number of decision points described in more detail in this paper can lead regulators through the process of designing a mechanism that best fits the situation.

Recommendations for the Commission that flow from our analysis, described in fuller detail at the conclusion of this paper, are as follows:

1. In the immediate short term, the Commission should create reporting

metrics on measures where it wants to see improvement, along with evaluation criteria, baselines, and targets.

2. After data are collected over time, incentives or penalties could be added to these measures.
3. The Commission should ensure that the metrics it chooses further its policy goals.
4. The process of reporting on these metrics should be transparent and public.
5. Decoupling can be more widely implemented to remove the utility throughput incentive.

II. Introduction

The Public Utilities Commission of Ohio (the Commission) has commenced a regulatory inquiry it is calling "Power Forward." The purpose of this inquiry is to examine various aspects of grid modernization, from its capabilities in the future to the technologies that will be needed to arrive at that future, and from the role of consumers and utilities, to the regulatory and rate-making reforms that will be needed to enable and encourage participation. From April 18-20, 2017, the Commission held its first meeting which it called "A Glimpse of the Future," which focused on innovation, the services a modernized grid could provide and the customer experience. The second meeting, held July 25-27, focused on technologies. The third meeting, scheduled for March 2018, will explore rate-making and regulation. The Regulatory Assistance Project (RAP) has been tasked, with the support of the US DOE and Lawrence Berkeley National Laboratory, to provide assistance to the Commission on the technical and financial analysis related to aspects of grid modernization. This advice will assist the Commission in the next phase of its inquiry. This paper focuses on the regulatory options that the Commission may consider to accelerate its efforts to modernize the grid of Ohio's four investor-owned utilities (IOUs).[1] These options include a discussion of performance regulation measures and metrics targeted toward better grid performance. The paper also reviews several rate designs that focus on the

[1] Technically, there are six operating companies as FirstEnergy has three electric distribution company subsidiaries. They are Cleveland Electric Illuminating Co., Toledo Edison Co., and Ohio Edison Co. The other three electric distribution companies are American Electric Power – Ohio, Duke Energy – Ohio, and Dayton Power and Light Co.

recovery of lost revenues and how these mechanisms align with the principles of cost causation. This paper is designed to assist the Commission in its consideration of the many regulatory issues that can help facilitate utility and customer engagement in a modern grid and advance the Commission's objectives.

III. Performance Metrics and Targets

A. Identification of Commission Policy Objectives and Scope of Authority Regarding Grid Modernization

In beginning its Power Forward initiative, the Commission made a focus on customers a priority. The overarching high-level goal of this grid modernization effort is to first educate Ohio stakeholders on the many options as they pertain to enhancing the distribution system and providing opportunities for customer engagement. After an assessment of the possibilities is complete, a plan to enact the reforms necessary to achieve the options identified as the best for Ohio may be developed to enable the Commission's vision for this endeavor. This report explores how both technological and regulatory innovation can improve the customer electricity experience in Ohio, and can recognize and articulate the kinds of benefits and services customers are seeking. Areas that can increase the customer electricity experience and engagement include smart meters, whose use continues to spread around the state, and energy storage. Another important aspect going forward is to determine the timing of these changes that customers may be expecting. This includes the existing barriers that impede progress and the incentives needed to stimulate progress in the right direction. To that end, the Commission has sought the input of expert stakeholders to share their views and help better frame the grid of the future. The Commission is seeking information on what technologies or changes are needed. This will help determine the innovative regulations and forward-thinking policies necessary to meet those needs in the future.

The Commission is looking toward developing regulatory policies that enable the development of a smart grid and that can encourage participation on the customer side of the meter, while incentivizing utilities to remove barriers that impede the customer experience. At this point, the Commission is exploring regulatory policies that have started to unfold in other states to determine what will work best for Ohio. In several past case settlements, the process of measuring performance has begun through the agreement on utility reporting on some metrics that relate in part to grid modernization. This paper will discuss performance regulation and explore incentive metrics. Where possible, we provide concrete measures that will enable the Commission to determine progress.

Scope of Commission authority

In the context of establishing rates, the Commission has the authority to review the practices of the utility and "… may consider the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered by the public utility, the value of such service to the public, and the ability of the public utility to improve such service and facility," and has the authority to order the utility "to improve such facility or service to a level determined by the commission to be efficient, sufficient, or adequate."[2] Thus, the Commission has the necessary authority to require performance incentive metrics. Moreover, key to the successful implementation of performance metrics is the Commission's ability to consider management practices, an authority granted to the Commission by law.

> *"… (T)he public utilities commission shall consider the management policies, practices, and organization of the public utility. The commission shall require such public utility to supply information regarding its management policies, practices, and organization. If the commission finds after a hearing that the management policies, practices, or organization of the public utility are inadequate, inefficient, or improper, the commission may recommend management policies, management practices, or an organizational structure to the public utility. In any event, the public utilities commission shall not allow such operating and maintenance expenses of a public utility as are incurred by the utility through management policies or administrative practices that the commission considers imprudent."*[3]

Finally, the law requires the Commission to establish a rate of return that is just and reasonable.[4] Thus, the Commission has the latitude to make adjustments to the rate of return based on utility practices as long as it is just and reasonable.

When Ohio restructured its electric industry, the Legislature articulated the state policy, which included, *inter alia,* to:

[2] OH Revised Code, Section 4909.152.

[3] OH Revised Code, Section 4909.154.

[4] OH Revised Code, Section 4909.152.

- (A) Ensure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service;
- (C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities;
- D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management, time-differentiated pricing, waste energy recovery systems, smart grid programs, and implementation of advanced metering infrastructure;
- (E) Encourage cost-effective and efficient access to information regarding the operation of the transmission and distribution systems of electric utilities in order to promote both effective customer choice of retail electric service and the development of performance standards and targets for service quality for all consumers, including annual achievement reports written in plain language;
- (G) Recognize the continuing emergence of competitive electricity markets through the development and implementation of flexible regulatory treatment;
- (J) Provide coherent, transparent means of giving appropriate incentives to technologies that can adapt successfully to potential environmental mandates;
- (K) Encourage implementation of distributed generation across customer classes through regular review and updating of administrative rules governing critical issues such as, but not limited to, interconnection standards, standby charges, and net metering;
- (M) Encourage the education of small business owners in this state regarding the use of, and encourage the use of, energy efficiency programs and alternative energy resources in their businesses.[5]

The development of a smarter grid may enable ancillary services, and the law specifically grants the Commission the authority to declare these services as competitive.[6] The Commission also has explicit statutory authority to review the

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[5] OH Revised Code, Section 4928.02.

[6] OH Revised Code, Section 4928.04.

utilities' distribution infrastructure which is a part of modernizing the grid.[7]

All these sections of the law—combined with other statutes set forth in later sections of this paper—provide yet further evidence that the Commission is on firm ground in seeking to implement performance standards through incentive metrics that address progress on grid modernization and the development of distributed energy resources (DERs) that will be consequently enabled.

B. Considerations for Developing Performance-Based Regulation Mechanisms

All regulation is incentive regulation,[8] whether it is traditional cost-of-service (COS) regulation, or performance-based regulation (PBR). Understanding the motivations inherent in traditional regulation is an important first step prior to establishing incentive mechanisms. This section explores the inherent drivers in traditional regulation, and important considerations when designing PBR for Ohio.

As a starting point, it is important to understand the legal and institutional context to determine whether and how innovative mechanisms such as performance-oriented incentives can be most useful. Understanding the implicit and explicit motivations that have evolved over time in the existing institutional arrangement is critical to being able to build a successful performance-based system that can influence utility behavior and achieve different outcomes.

An assessment of the ownership of the regulated entity (i.e., investor-owned, etc.), the financial and management structure, and how it maximizes revenue and profit is important prior to creating an incentive. Traditional COS regulation sets a rate of return on rate base,[9] and so the utility is incentivized to increase revenue (and earnings for shareholders if privately owned) by investing in its own plant, whether that is generation, transmission or distribution plant.[10] The adoption of distributed generation can raise tensions within this system, because it is seen to reduce

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[7] OH Revised Code, Section 4928.111.

[8] Bradford, P. (1989). Incentive Regulation from a State Commission Perspective. Remarks to the Chief Executive's Forum.

[9] For publicly owned systems with no private shareholders, there is still revenue and earnings pressure. Universally, lenders (bondholders) demand certain coverage ratios to justify investment-grade interest rates and enable reasonable retail rates that drive revenue concerns. Other hidden incentives for growth include federal and global aid programs in which loan administrators pursue volume of loans and grants placed. A related concern is setting administrator salaries keyed to the size of the electric system.

[10] This is known as the Averch-Johnson effect, which is identified by economists as the tendency of regulated companies to engage in excess capital investments to increase their profits.

utilities' new for new plant as well as sales.

PBR works around this tension, creating a framework in which utilities' compensation and returns are connected to service goals, targets, and measures. This enhances the grid, gives customers more options, and keeps the utilities financially viable. Recognizing this, some jurisdictions with IOUs are undertaking an evolution from a regulatory emphasis on a rate-of-return structure to more of an emphasis on specific outcomes, achieved through performance incentive structures. PBR provides a framework that connects goals, targets, and measures to utility performance, compensation, and investor returns. Each jurisdiction needs to assess inherent incentives, structures and goals, and then determine the PBR structure that is most conducive to meeting unique jurisdictional needs. PBR frameworks can look as different and novel as the UK's Revenues = Incentives + Innovation + Outputs (RIIO) initiative, which features a broad framework that shifts significant aspects of regulation to an incentive-based structure. Alternatively, PBR can look like a carefully designed performance incentive mechanism (PIM)—or set of PIMs—layered onto a more traditional regulatory approach.[11] This paper focuses more on the examples of PBR and how Ohio can use performance incentives to begin to shift utility behavior within an existing regulatory framework.

When developing performance-based mechanisms, attention to a few specific points can avoid difficulties. These points include aligning the goal with public interest, providing motivation beyond business as usual, exploring how performance incentives can work with other programs, and ensuring that the amount of the incentive is appropriate.

It is important to stress that in developing incentive mechanisms, the overall goal is to align the public interest with the utility interest in order to motivate utilities to promote internal policies and actions that lead to a more resilient and efficient grid. In so doing, however, it should not cause rates to increase in a way that would adversely impact ratepayers. Weighing the costs against the benefits is important to avoid adverse effects for ratepayers.

[11] This paper does not focus extensively on the UK example or other examples from around the world. For more information on experiences in other jurisdictions see Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Migden-Ostrander, J., Rosenow, J., Wang, X., Zinaman, O., and Logan, J. (2017). Next-Generation Performance-Based Regulation. Golden, Colorado: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf.

PBR does not need to have financial incentives (or disincentives) associated with it to be useful. Implementing performance incentives without financial repercussions builds experience both at the utility and with the regulator with particular targets and metrics. When a metric is ready to have an incentive attached to it, those incentives should be sized in alignment with desired results. Developing performance metrics is a good interim step to measure progress by the utility. Reporting should be transparent and posted on both the utility and Commission webpage for anyone to review.

When constructing performance metrics, it is important that incentive payments build on business as usual, and provide motivation to utility management to move beyond it. Understanding the business-as-usual outcomes prior to setting incentives will help avoid a situation in which a utility receives an additional payment with no added benefit to customers. Understanding of the business-as-usual outcomes is often taken from historic experience, regulator experience with specific areas of utility operation, benchmarking against other utilities, or modeling. Regulators can modify and adjust rewards or penalties later, if necessary, to calibrate incentives with desired outcomes.

PBR works well with existing COS regulation. Performance incentives such as shared savings have been used successfully for many years in Ohio and elsewhere in the United States to incentivize utilities to achieve specific energy efficiency criteria.[12] Combining multi-year rate plans (MRPs) with performance incentives that allow utilities to earn revenue even with lower sales can incentivize utilities to pursue energy efficiency measures. These proven mechanisms illustrate the potential to effectively layer PBR (MRPs) and performance incentives (additional efficiency incentives) onto existing regulatory structures and yield results to incent both efficient operations and expenditure control and cost-effective energy efficiency. Section D of this report will highlight a variety of PBR options that may be applicable in Ohio beyond the experience with energy efficiency incentives.

Performance incentives are more successful if they represent a sufficient amount of

[12] In 2008, SB 221 passed the General Assembly. Among many other items, this legislation included an Energy Efficiency Resource Standard. Prior to this legislation, the utilities had been engaged in energy efficiency to varying degrees; however, the legislation established a trajectory for progress, with gradually increasing energy efficiency targets to produce a cumulative reduction in load of 22.5 percent by 2025. The programs implemented by the utilities used a baseline determined through a rolling three-year average of previous years' sales and were based on the utilization of the Total Resource Cost Test among other tests and included a shared savings incentive that varied from utility to utility based on the agreements reached in settlements and through the stakeholder collaborative process.

earnings warranting the attention of utility executives. If the primary measures of revenue remain invested capital, sales, size of utility, and revenue (in private utilities), then performance incentives with miniscule incentives will have little impact. In other words, it may not work to have all but a small fraction of revenue determined by invested capital in traditional rate base and sales which will drive utility revenue and profitability. To counter this inherent disincentive, the measure should be highly public and transparent so as to impact utility performance through public and stakeholder recognition and transparency. If the measure is not highly public, then attaching a moderate basis point gain or loss to achievement of the performance criteria is generally necessary to get utility management attention, particularly where such attention and deployment of utility resources is necessary to achieve a particular outcome.

C. Performance-Based Regulation to Promote Economic Utility Operations

Multi-Year Rate Plans With Cost or Revenue Caps

MRPs can be effective in incentivizing efficient utility operations.[13] This early approach to PBR focuses on providing the utility with an incentive to save money. Early versions of MRPs set fixed rates over a number of years and allowed the utility to retain all or some portion of the cost savings resulting from efficiency gains. Later versions focused on a revenue cap, requiring revenue and savings beyond a certain level to be shared with or refunded to ratepayers. More recent versions include a predetermined formula or other mechanism that allows revenue or rates to change during the plan. The purpose of MRPs is to motivate efficient operations and low-cost service while maintaining reliability and customer service. Some statistical studies of vertically integrated electric utilities indeed suggest, and those that operate for long periods without rate cases indicate, that MRPs encourage superior cost management.[14]

Nonetheless, as with many modifications to regulation, experience has exposed some areas of concern that merit monitoring. Careful crafting of the MRP

[13] Lowry, M.N., Woolf, T., and Schwartz, L. (2016). Performance-Based Regulation in a High Distributed Energy Resources Future. Lawrence Berkeley National Laboratory. Retrieved from https://emp.lbl.gov/publications/performance-based-regulation-high.

[14] Lowry et al., 2016, p. 31.

mechanism can proactively address these concerns. With cost-cutting incentives under MRPs comes a higher possibility that utilities would save money not by operating more efficiently but by reducing quality of service. For example, if a utility is allowed to keep all of the savings from more efficient operations, it might lay off customer service representatives or reduce line crews that respond to service outages and keep the saved expense as profit while customer service languishes. This concern is addressed with service quality measures and typically a negative incentive design (e.g., a penalty for failing to meet certain standards).

Performance metrics for service quality identify service goals, set targets for acceptable service levels, and measure outages (by number or duration, or both), meter reading disputes, time to answer consumer phone line, number of customer complaints, time to provide a new service connection, time to resolve consumer complaints, and similar customer service and reliability measures. Specific operational data sets from each utility can form the basis for these. Each measure can be translated into a reward or penalty or both to modify revenue. Some customer service targets are likely to assist low- or moderate-income ratepayers who may be more likely to access consumer phone lines, have service disconnected, and file complaints, while other targets such as overall reliability benefit all ratepayers.

MRPs often feature a rate cap or a revenue cap. A rate cap literally limits the rate a utility can charge its customers. A utility is allowed to keep some or all efficiency gains so long as rates do not increase. A revenue cap limits how much revenue a utility can recover so utility revenue cannot exceed a certain level. The two concepts can be combined or augmented with a formula, such as tying return on equity to a market index or a process, such as annual review of capital. Each may result in an adjustment of rates and revenues during the plan. A potential concern is that MRPs with rate caps or revenue caps may slow revenue growth below what is necessary for system investments. This is a concern for regulators if large expenditures are desired. For this same reason, utilities may oppose MRPs if a utility is planning large investment in plant. Conversely, if PBR may produce faster-than-projected revenue growth or rate creep, consumer advocates may oppose it.[15] That tension may lead to productive discussion and mechanism design

[15] Regulatory Assistance Project (2000). Performance-Based Regulation for Distribution Utilities. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/rap-performancebasedregulationfordistributionutilities-2000-12.pdf.

if decisions on PBR occur in a transparent manner.

Any PBR scheme must account for factors that are significant in scale and outside of the utility's control that might affect metric achievement. For MRPs, an adjustment is commonly used to identify specific factors defined by metrics outside the utilities' control such as weather and inflation. Advanced PBR target and metric setting can step beyond merely identifying risk within and outside the utility's control to consider who currently bears the risk for non-achievement, who pays for achieving or not achieving the goals, who can most efficiently address the risk (utilities, consumers, third parties), and how the risk will affect the utility's, customer's, and third parties' decisions.[16] Risk can translate into long-term costs that are not currently defined; the allocation of risk determines who pays those indefinite long-term costs. MRPs shift some of the risk of efficient business operations from ratepayers to the utility, which is typically efficient because utility management is in a superior position to achieve efficient operations compared to regulators and ratepayers.

MRPs can materially improve utility cost performance and therefore provide a promising strategy for addressing some challenges facing Ohio's utility industry. MRPs can improve the efficiency of regulation under the right set of circumstances. The additional scrutiny associated with MRPs means utilities will have to improve their budgeting and project management practices in order to provide information the Commission requires to set the appropriate rate and time frame. As noted above, there is a need to develop complementary operational incentives to maintain and improve reliability and customer service through the most effective mix of operational and capital investment decisions.

D. Identification of Potential Targeted Incentives

This section identifies some incentive mechanisms that may be useful in Ohio. These suggested mechanisms would build on Ohio's successful experience with energy efficiency incentives, provide an opportunity to apply PBR more broadly to many aspects of utility operations, and focus on high-priority policy areas for Ohio.

[16] Regulatory Assistance Project, 2000, p. 38.

1. Improvements to Utility Reliability

Performance metrics for reliability are well-understood even as they vary in detail and application across jurisdictions. The primary performance measures of reliability are duration and frequency of outages measured by System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). A less widely used measure is Momentary Average Interruption Frequency Index (MAIFI), and power quality is a measure of reliability. Table 1 on the following page explains the purpose of each metric and provides a formula for calculating each metric.

The Ohio Commission has adopted SAIFI and CAIDI reliability metrics and requires utilities to report annually on power interruptions.[17] MAIFI performance standards would hold the utility to a goal of avoiding losses of customer service, which is a higher customer-based goal. This is particularly important for industrial and commercial customers—but all customers benefit. Additionally, the Commission approves performance standards for each utility; failure to meet those standards for two consecutive years is considered a violation of the Commission's rules.[18] This is a PBR setup with a negative incentive; it penalizes the utilities for unacceptable performance although the negative incentive is unclear. While Ohio regulates reliability to ensure no utility's performance falls below an accepted standard, it does not incent performance beyond those standards.[19] Performance incentives for reliability can inspire utilities to strive for performance that exceeds the minimum requirements for reliability.

One avenue to do this would be for the Commission to modify its reliability regulations to recognize a minimum threshold for performance above which utilities could excel. Such a minimum threshold could be developed, for example, from each utility's historic performance or from the historic performance of all utilities in the state or region.

[17] OH Administrative Code 4901:1-10-10, 2014. See also Ohio Public Utilities Commission (undated). Electric Reliability Performance Data. Retrieved from: https://www.puco.ohio.gov/industry-information/statistical-reports/electric-reliability-performance-data/.

[18] OH Administrative Code 4901:1-10-10, 2014.

[19] OH Administrative Code 4901:1-10-10, 2014.

Table 1: Reliability Performance Metrics[20]

Metric	Purpose	Metric Formula
System Average Interruption Duration Index	Indicator of sustained interruptions experienced by customers	Total customer minutes of sustained interruptions / total number of customers
System Average Interruption Frequency Index	Indication of how many interruptions are experienced by customers	Total number of customer interruptions / total number of customers
Customer Average Interruption Duration Index	Indicator of the length of interruptions experienced by customers	Total minutes of sustained customer interruptions / total number of interruptions
Momentary Average Interruption Frequency Index	Indicator of momentary interruptions experienced by customers	Total number of momentary customer interruptions per year / total number of customers
Power Quality	Indicator of voltage changes, which can cause damage to end-use equipment and frequency deviations	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker; CPS[21] 1 and 2 that measure frequency excursions

[20] Whited, M., Woolf, T., and Napoleon, A. (2015). Utility Performance Mechanisms: A Handbook for Regulators. Cambridge, Massachusetts: Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

[21] Cyber-physical systems (CPS) are engineered systems that are built from, and depend upon, the seamless integration of computation and physical components. Advances in CPS will enable capability, adaptability, scalability, resiliency, safety, security, and usability that will expand the horizons of these critical systems. CPS technologies are transforming the way people interact with engineered systems, just as the Internet has transformed the way people interact with information. New, smart CPS are driving innovation and competition in a range of application domains including agriculture, aeronautics, building design, civil infrastructure, energy, environmental quality, health care and personalized medicine, manufacturing, and transportation. See National Science Foundation (undated). Cyber-Physical Systems. Retrieved from: https://www.nsf.gov/funding/pgm_summ.jsp?pims_id=503286.

Setting reliability goals, performance criteria, or metrics is universally recognized as desirable core regulatory function since it effectuates one of the central public utility service goals: safe and reliable service at just and reasonable prices. That said, establishing the precise performance criteria and metrics should also be careful to be laudatory allowing for low-cost achievement through performance rather than high-cost investments that should receive full scrutiny in a rate case proceeding. Improvements in SAIFI, SAIDI, or CAIDI of X percent could allow for a rate-of-return adder of 5 to 10 basis points—not enough to be more than laudatory but enough to compensate superior utility performance.

How Much Reliability is Too Much?

Norwegian regulators approached the reliability quandary by asking utility customers how much they value reliability using customer surveys to construct a willingness-to-pay curve for different levels of system reliability. The Norwegians then use a PBR scheme to have their utilities internalize the reliability valuation by customers. Norway uses revenue cap regulation to control utility costs. It allows utilities to retain cost savings from operating below approved costs. Because revenue cap regulation can create an incentive to cut costs in ways that impact system reliability, this system adjusts utility revenues each year based on the costs of outages to customers. Thus, if outages increase, utility revenue is reduced, or if outages are reduced below a baseline level, the utility receives higher revenues the next year.[22]

Reliability is good, but too much reliability is expensive and may be more than ratepayers want to pay. It is important not to fall into the "no-amount-of-reliability-is-enough" trap because reliability investments are limitless. The amount of reliability that regulators should require and how to measure it are perennial utility questions: How much reliability should be required? Another way to ask the question is: How much reliability do customers want to pay for in their electricity service? Moreover, the level of desired reliability may vary among customer classes. A residential customer may prefer the inconvenience of a momentary outage rather than paying a higher rate to avoid it. On the other hand, for Ohio's polymer industry, a momentary outage can be very costly to operations, and from a cost-benefit standpoint, customers in the industry may be willing to

[22] Whited et al., 2015.

pay more. Nevertheless, the Canadian province of Alberta recognized the quandary of balancing the appropriate level of reliability squarely in its decision rejecting a reward-based performance incentive for exceeding expected reliability standards, finding that "… in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher price of service quality levels that they may not want or cannot afford."[23]

The incentive mechanism in Illinois provides an example of a reliability incentive mechanism that was applied through a formula rate tariff structure. As part of a grid modernization initiative in Illinois, the Illinois Commerce Commission (ICC) adopted a PBR formula rate tariff.[24] These tariffs were approved under Illinois' Energy Infrastructure Modernization Act, which authorized $3.2 billion in grid hardening and smart meter investments. The guiding principle of the act and tariff is to achieve increased grid reliability and operational efficiency by offering the utilities increased certainty around capital investments such as distribution reclosers, substation improvements, pole reinforcements, undergrounding targeted lines, and vegetation management.[25]

The ICC approved formula rates for participating utilities providing greater utility confidence that grid modernization expenses would be found prudent with a set rate of return to be adjusted based on known objective factors annually. In exchange for this formula rate treatment, participating utilities are required to file multi-year metrics with the ICC to improve performance over a ten-year period, including reliability performance.

After installing grid automation and more intelligent sensors and the range of approved grid hardening and smart grid investments described above, the utilities reported improvements in outage frequency and duration.[26] But the utilities failed

[23] Whited et al., 2015, p. 41.

[24] IL Compiled Statutes, Section 16-108.5, 2017.

[25] McCabe, A., Ghoshal, O., and Peters, B. (2016). A Formula for Grid Modernization? Public Utilities Fortnightly. Retrieved from: https://www.fortnightly.com/fortnightly/2016/05/formula-grid-modernization.

[26] Both utilities, Ameren and Commonwealth Edison, report reliability improvements. See Ameren Illinois Co. (2015). Modernization Action Plan. Retrieved from: https://www.icc.illinois.gov/downloads/public/edocket/406271.pdf; Commonwealth Edison Co. (2015). Multi-Year Performance Metrics. Retrieved from: https://www.icc.illinois.gov/downloads/public/edocket/402546.pdf.

to meet the 75 percent improvement performance criteria the ICC set and have been penalized with a 5-basis point reduction in authorized return on equity (ROE) as a result. This reduction of ROE resulted in an approximate $2 million reduction in Commonwealth Edison's roughly $2.5 billion annual revenue requirement.[27] This is a negative incentive scheme which imposes a relatively low penalty reduction in an approved formula rate when reliability criteria are not met. This penalty is lower than the utilities' increased revenue from formula rates, which is what makes it relatively low compared to the utility benefit.

2. Improvements to Safety

PBR for safety provides a framework whereby the Commission, utilities, and stakeholders including utility workers and the public can identify measurable outcomes to assess safety performance. Goals, performance criteria, and measures of safety performance are necessary for effective safety management and decision making. With safety as with other criteria and goals, ideally, a measurement strategy should provide a metric range or suite of metrics, rather than a single "magic number" that dictates whether a strategy succeeds or fails.[28] These measures also should be interactive, cover all aspects of the systems that they address, and reflect both system failures (e.g., accidents, incidents, regulatory violations) and indicators of the proper functioning of critical system components.[29]

PBR for safety generally focuses on employee and public safety goals. Safety goals are often to achieve an improving level of both employee and public safety. Goals, performance criteria, and metrics are identifiable for both employee safety and public safety. Performance metrics for each category commonly include:

Employee safety performance metrics:

- Total safety incident rate;
- Injuries requiring lost employee time measured by days;
- Fatalities or loss of employee capabilities;

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[27] McCabe et al., 2016.

[28] Safety Management International Collaboration Group (2010). A Common Approach to Safety Performance Management. Retrieved from: https://www.skybrary.aero/bookshelf/books/1780.pdf.

[29] Safety Management International Collaboration Group, 2010.

- Days away, restricted, and transfer case rate; and
- Days away from work case rate due to safety incidents.

Public safety performance metrics include:

- Incidents, injuries, and fatalities (electric); and
- Emergency response time (electric).

In sum, these metrics aim to ensure that no utility employee or member of the public faces excessive risk.[30] The following charts explain each metric's purpose and how to calculate each.

Table 2. Employee Safety Performance Metrics[31]

Metric	Purpose	Metric Formula
Total Case Rate	Indicator of employee injuries, fatalities, and productivity losses due to work-related incidents	(Number of work-related deaths, days away from work, job transfers or restrictions, and other recordable injuries and illnesses times 200,000[32]) / employee hours worked
Days Away, Restricted, and Transfer Case Rate	Indicator of employee injuries, restrictions, and productivity losses due to work-related incidents	(Number of work-related days away from work and job transfers or restrictions due to work accidents times 200,000) / employee hours worked
Days Away From Work Case Rate	Indicator of employee injuries and productivity losses due to work-related incidents	(Number of work-related days away from work due to work accidents times 200,000) / employee hours worked

[30] Whited et al., 2015.

[31] Whited et al., 2015.

[32] An incidence rate of injuries and illnesses may be computed from the following formula: (Number of injuries and illnesses X 200,000) / Employee hours worked = Incidence rate. 200,000 represents the number of working hours per year for 100 full-time equivalent employees (40 hours a week for 50 weeks). US Department of Labor (2013). How to Compute a Firm's Incidence Rate for Safety Management. Retrieved from: https://www.bls.gov/iif/osheval.htm.

Table 3. Public Safety Performance Metrics[33]

Metric	Purpose	Metric Formula
Incidents, injuries, and fatalities (electric)	Indicator of incidents, injuries, and fatalities associated with contact with the electric system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by type of activity
Emergency response time (electric)	Indicator of speed of response to emergency situations involving the electric system	Percent of electric emergency responses within 60 minutes each year
Incidents, injuries, and fatalities (gas)	Indicator of incidents, injuries, and fatalities associated with the gas system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by apparent cause
Emergency response time (gas)	Indicator of speed of response to emergency situations involving the gas system	Average minutes for gas emergency response
Leak repair performance (gas)	Indicator of speed of response to non-emergency situations involving the gas system	Average days for repair of minor and non-hazardous leaks

The data for these metrics generally are readily available from the utility, as most utilities have been required to report both employee and public safety metrics for decades. Utilities record and report on employee safety and data on injuries and fatalities from gas system incidents.[34]

Regulators can set targets for safety goals based on historic utility specific data, trends, or industry benchmarking. As with other measures, the targets should be high enough to justify any incentive. Regulators may compile historical data for these metrics from each utility and track and compare performance relative to the historic baseline or relative to other utilities within the state or region. The

[33] Whited et al., 2015.

[34] 49 C.F.R. § 191.5.

question then becomes how much ratepayers should pay to incentivize higher utility performance or whether better performance is achievable based on industry norms and performance below that level should be subject of a negative incentive (penalty) for performing below acceptable levels of employee or public safety.

As with all PBR, it is important to understand the type of incentive created and to safeguard against unintended consequences. It is helpful to ask: How can this incentive go wrong? Can it be gamed? Are the right incentives set up? A case that illustrates incentives that in practice produced unintended consequences is from California. When the California Public Utilities Commission required reporting of employee injury data for rewarding workplace safety, it later found that supervisors encouraged non-reporting, self-treatment, or treatment by personal physicians and other measures in order to avoid the creation of internal utility injury reports. Further, the reporting of injury data by group and the utilities' offering of incentives on a group basis within the company led to employee desires to see their group or unit safety rankings justify a bonus, and thus created a disincentive to report injuries.[35] This PBR system's intended focus on worker safety improvements instead produced an employee incentive to avoid reporting and a management incentive to falsify data reporting. The lesson from this California experience is to carefully consider internal data management and reporting within the utility, particularly when there is a reward and penalty aspect of an incentive that affects individual and group employee compensation. The nature of the safety incentives and group-based incentives in some units created an unintended effect that compromised the purpose of the performance goal itself.[36]

3. Improvements to End-Use Efficiency

Some background on end-use efficiency is appropriate prior to exploring PBR metrics. As we will further discuss in Section IIIB below on alternative compensation plans, it takes additional measures to support energy efficiency to provide some forms of utility incentives for energy efficiency performance or at

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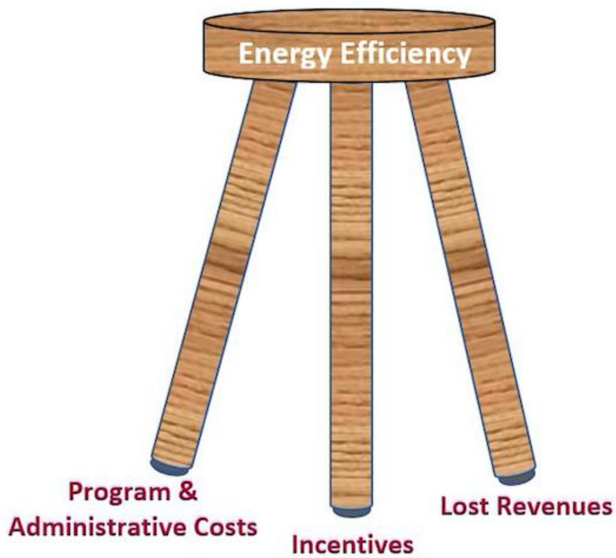
[35] Whited et al., 2015.

[36] Another booby trap is that a focus toward a particular metric may take utility employee attention away from other tasks that do not have a reward or any reported metric, and instead focus their time on tasks that do influence achievement of performance targets, such as the customer experience or societal benefit. Regulators can address this with a broader array of metrics that are reported without reward (a scorecard) such that all utility performance is subject to public disclosure and a likely future correction.

least remove disincentives. Effective programs are often referenced as a three-legged stool to support energy efficiency efforts.[37]

Figure 1: The Three-Legged Stool of Energy Efficiency Program Support



The three legs are program and administrative cost recovery, lost revenues (resulting from a utility selling less of its product), and incentive payments. Each has a separate function. Administrative cost recovery allows the utility to be made whole for its expenditures on a dollar per dollar basis. Lost revenues address the throughput incentive by allowing the utility to recover lost revenues resulting from decreased sales. An incentive payment provides just that: an incentive so that utilities can earn a return or payment for good performance. This is to help dissuade them from choosing a capital expenditure to meet load requirements for which they would earn a return for their shareholders. The goal is to level the playing field so that utility obligations to their shareholders which influence their decision making align better with the public interest of lower-cost options.

Performance incentives for efficiency can motivate utilities to meet or even exceed savings targets established by law or rule. At least 26 states have used performance incentives to encourage energy efficiency deployments. These incentives include allowing a utility to earn a) a percentage of program costs for achieving a savings

[37] National Action Plan for Energy Efficiency (2007). Aligning Utility Incentives with Investment in Energy Efficiency. Retrieved from: https://www.epa.gov/sites/production/files/2015-08/documents/incentives.pdf.

target (eight states), b) a share of achieved savings (13 states), c) a share of the net-present-value of avoided costs (four states), and d) an altered rate of return for achieving savings targets (one state).[38] These incentives either encourage attainment of savings targets or reward utilities for achieving or going beyond these targets. For example, Colorado has a performance incentive that returns one percent of net energy efficiency savings to the utility for every five percent the utility exceeds its savings goals.[39]

Text Box: Market Demonstration of Energy Efficiency Benefits

Another way to measure the benefits of energy efficiency is to examine how much energy efficiency has been sold into organized markets to in effect lower the market clearing price. This further demonstrates the effectiveness of the energy efficiency because it is not only a wholesale market resource, but it suppresses the ultimate price that customers must pay for wholesale power. The table below[1] compares PJM and NE-ISO, two active markets for DSM.

Table 4: Comparison of EE Capacity and Overall Cleared Capacity, PJM vs. ISO-NE

Table 5: Comparison of EE Capacity and Overall Cleared Capacity, PJM vs. ISO-NE

	Market	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Total Capacity	ISO-NE	36,996	37,501	36,918	36,309	36,220	33,702
	PJM	139,487	156,493	153,683	168,631	173,313	171,129
EE Capacity	ISO-NE	1,062	1,295	1,486	1,770	1,752	2,059
	PJM	569	679	822	923	1,117	1,340
EE Capacity as a % of overall obligation	ISO-NE	2.9%	3.5%	4.0%	4.9%	4.8%	6.1%
	PJM	0.4%	0.4%	0.5%	0.5%	0.6%	0.8%
EE Payment Rate ($/kW-month)	ISO-NE	$2.951	$2.951	$3.209	$3.434	$3.150	$7.025
	PJM	$0.501	$0.843	$3.831	$4.095	$1.806	$3.644

Note: The payment prices used above are the "Rest-of-Pool" rate in ISO-NE, and the "RTO" rate in PJM, which has been converted from $/MW-day to $/kW-month for purposes of comparison.

[38] State and Local Energy Efficiency Action Network (2016). SEE Action Guide for States: Energy Efficiency as a Least Cost Strategy to Reduce Greenhouse Gases and Air Pollution and Meet Energy Needs in the Power Sector. Prepared by: Lisa Schwartz, Greg Leventis, Steven R. Schiller, and Emily Martin Fadrhonc of Lawrence Berkeley National Laboratory, with assistance by John Shenot, Ken Colburn, and Chris James of the Regulatory Assistance Project and Johanna Zetterberg and Molly Roy of the US Department of Energy. Retrieved from: https://www4.eere.energy.gov/seeaction/system/files/documents/pathways-guide-states-final0415.pdf.

[39] ACEEE (2016). Colorado Efficiency Scorecard. Retrieved from: https://database.aceee.org/state/colorado

Ohio has implemented shared savings mechanisms for energy efficiency, which vary by utility.[40] The following description of shared savings mechanism may be useful when reviewing mechanisms in place. Shared saving or percentage of program revenue approaches are commonly used to provide utilities with a share of the savings from successfully implementing conservation and efficiency programs. A specific performance criteria could be the percentage of a utility's load that was served with efficiency measures, or certain cumulative reductions in retail sales, either in percent or in kWh. The incentive could be tied to achievement of a percentage or quantity of savings above and beyond what is required by the energy efficiency resource standards in place.

A shared net benefits approach such as the example outlined here works well if it clearly identifies the shared benefits, ensures the utility appropriately controls costs, and uses a mechanism that cannot be gamed. Shared net benefit mechanisms can blunt the incentive for utilities to control costs, which is otherwise a prime motivation for implementing PBR, thus the need to ensure incentives are built to safeguard adequate program and benefit cost control.

One method to build in cost control incentives to a shared benefits approach is a deadband approach. A deadband approach adopts a range around a performance level that results in no incentive impact until the range is exceeded and then limits the upper range of the incentive as well. Identifying a band of savings where net benefits are likely to occur under business-as-usual scenarios is the first step to identifying savings where no incentive should apply. The deadband mechanism can be designed to apply benefits outside a band—savings as low as business as usual or savings unusually high—where earnings are not affected.

After the goal is clearly articulated, performance criteria and targets identified, then identification of the reporting metrics is critical to evaluating compliance and incentive payments under a performance incentive metric. Energy efficiency savings are often measured in terms of energy (MWh savings) or peak reductions (MW). The comparison to a baseline to measure what is "saved" is then necessary. Baselines can be the previous year's sales, previous peak periods or some projected figure for load or peak growth. There could be a separate multi-year rolling average to assess trends and whether individual years are anomalous.

[40] ACEEE (2016). Ohio Efficiency Scorecard. Retrieved from: https://database.aceee.org/state/ohio

The following example shows how a metric could be developed in a low load growth context, where an energy efficiency metric could track savings in the utility's total annual weather-adjusted kWh retail sales compared to the previous calendar year. The metric could be designed to be consistent with whatever reporting and tracking the utilities already must complete as a part of their compliance with the energy efficiency resource standard. Energy efficiency program savings are often calculated on a deemed saving[41] basis for measures installed so measuring actual kWh sales would provide a real-kWh verification on the deemed savings approach and ensure the utility has a stake in reducing actual consumption (not just showing deemed savings). This would help ensure that the data used to track performance are synced with data and measures already familiar to stakeholders, and determinations of performance are more objective.

Energy efficiency and demand response potential studies can identify the amount of investments that would be cost-effective for the utility to make. These studies can help regulators identify and define specific resource investment targets and costs. With this information, regulators can better calculate the amount of incentive that should be tied to various levels of achievement as well as metrics to accurately measure savings benefits and costs.[42]

To summarize, the energy metrics to be tracked are typically KWh energy savings or reductions in peak, or both. Since energy efficiency programs often use deemed savings approaches, using actual utility data to measure performance incentives would provide strong verification with readily available and high-quality data. The baseline or prior year's sales makes sense to set an easily attainable baseline after comparisons to ensure load and sales are neither unduly growing nor shrinking.

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[41] Deemed savings values are estimates for the energy and/or demand savings for a single unit of an installed energy efficiency measure that (1) have been developed from data sources (such as prior metering studies) and analytical methods that are widely considered acceptable for the measure and purpose, and (2) are applicable to the situation being evaluated. For energy efficiency programs, deemed savings approaches generally are used for projects with well-documented savings values—for example, appliances, lighting, and computer equipment. ACEEE research from 2012 found that 36 states use some type of deemed savings values in their evaluation frameworks, and that 26 states cite the use of sources or databases from other states. American Council for an Energy-Efficient Economy (undated). Evaluation, Measurement & Verification. Retrieved from: https://aceee.org/print/sector/state-policy/toolkit/emv.

[42] For more on energy efficiency see: Lazar, J., and Colburn, K. (2013). Recognizing the Full Value of Energy Efficiency. Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency. See also Kramer, C., and Reed, G. (2014). Ten Pitfalls of Potential Studies. Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/energyfutures-kramerreed-tenpitfallsesdraft2-2012-oct-24.pdf.

4. Improvements to System/Operational Efficiency

Performance incentives also can focus on achieving system efficiencies. There are many ways to achieve system efficiency, and for that reason it is often defined and identified differently depending on the needs of the jurisdiction. For example, where peak demand is driving the need for bulk power and transmission investment, a focus on peak load reduction will bring system efficiencies and reduce costs to customers. There are numerous activities that utilities can undertake to improve the performance and efficiency of electric transmission and distribution systems, with resulting improvements to grid reliability, efficiency of electricity delivery, reduced system losses, and increased capacity utilization (requiring, over time, less capital investment). This section focuses on ways to optimize system efficiency via strategies that get the same or greater capability from a utility's existing system, saving energy and thereby reducing the need for upstream generation and system upgrades. Examples of efficiencies in place now include optimizing voltage regulation and power factor management and enhancing levels of grid intelligence to meet energy demands.

Focusing on optimizing voltage as a system efficiency measure is something that many jurisdictions have already done. US power quality regulations generally require that voltage be delivered to homes and businesses within 5 percent of the nominal 120 volts that equipment is designed to use. Because voltage levels drop along the length of distribution feeders, utilities often maintain higher voltage levels at the beginning of feeders to ensure that at least 114 volts will be delivered to the last customer served by the feeder.[43] The result is that many customers receive higher voltages than they need. Maintaining higher voltages always requires additional energy, which means that losses of 3 to 7 percent occur while delivering electricity to customers. Demand response and peak reduction strategies can reduce losses in the transmission and distribution of electricity by reducing loads during periods at which power lines and other equipment are most stressed and losses can be as high as 20 percent.[44] Peak load reduction could be tracked using a metric of instantaneous or five-minute peaks compared to energy fed into the system instantaneously or over the same five minutes at supply nodes, and requiring reporting over time. A simple tracking metric would help the

[43] National Association of Clean Air Agencies (2015). Implementing EPA's Clean Power Plan: A Menu of Options, Chapter 5. Retrieved from: http://www.4cleanair.org/sites/default/files/Documents/Chapter_5.pdf.

[44] National Association of Clean Air Agencies (2015).

Commission establish a baseline from which to develop further performance metrics in the future. A more basic metric would be tracking the number and percentage of distribution lines using sensing from an advanced meter as part of a voltage regulation scheme.

Table 5: System efficiency metrics[45]

Metric	Purpose	Metric Formula
Load Factor	Indication of improvement in system and customer load factors over time	Sector average load / sector peak load Monthly system average load / monthly system peak load
Usage per Customer	Indication of customers' energy consumption changes over time	Sector sales / sector number of customers
Flexible Resources	Indication of the capacity of supply side resources to quickly respond to changes in net load	MW of fast ramping capacity (load following resources capable of 15-minute ramping and regulation resources capable of 1-minute ramping)
System losses (electric)	Indication of reductions in losses over time	Total electricity losses / MWh generation, excluding station use
System losses (gas)	Indication of reductions in gas losses over time	Total gas losses / total sales
Demand response	Indication of participation and actual deployment of demand response resources	Percent of customers per year Number of customers enrolled MWh of demand response provided over past year Potential and actual peak demand savings (MW)

In New York, the Public Service Commission (PSC) took a different and multi-pronged approach to the same issue as part of the state's Reforming the Energy

45 Whited et al., 2015, tables 11 and 12.

Vision (REV) initiative. The New York PSC's order implementing performance incentives in the REV process mandates that the utilities propose both a peak reduction target and a load factor improvement target.[46] The PSC recognized peak reduction as one of the most immediate priorities due to its impact on overall system efficiency. The PSC called for peak reduction targets that are either a specific MW objective for system peak or a percentage reduction from a defined MW amount. Only positive earnings adjustments will be used for these initial incentives, with the size of the adjustment graduated to the extent of the achievement. The PSC will examine the contribution of each component of the program when determining the size of the incentive in the future.

5. Enhancements to the Retail Market

Data access

Utilizing real-time energy cost and usage data systems is critical to optimize the efficiency of energy production and delivery.[47] Yet utilities are reluctant to do so, as there are barriers to overcome and no incentive to do so. Sharing this data can foster system optimization by facilitating access to utility and customer data that allow for more efficient decisions. The Commission can mandate sharing of distribution system data by order or rule. The scale and granularity of data sharing for system data is the subject of significant attention in jurisdictions as disparate as New Hampshire and California, Maryland and New York, which have both vertically integrated and restructured utilities.

Sharing of customer data usually requires customer consent. Because individual customers are increasingly interested in advanced customer premises technologies, one of the imperatives for grid modernization design is for utility data usage systems to allow and facilitate customer consent for customers interested in sharing their data with third-party vendors.

For many purposes, utilities can share anonymized data on a circuitwide or nodal

46 New York Public Service Commission, Case No. 14-M-0101, Order on May 19, 2016. Retrieved from: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BD6EC8F0B-6141-4A82-A857-B79CF0A71BF0%7D. See pages 25 and 75 for a discussion of these metrics.

47 Fox-Penner, P. (2010). Smart Power: Climate Change, the Smart Grid and the Future of Electric Utilities. Washington, D.C.: Island Press; and Valocchi, M., Juliano, J., and Schurr, A. (2010) Switching Perspectives: Creating New Business Models for a Changing World of Energy. IBM Institute for Business Value. Retrieved from: https://www-01.ibm.com/common/ssi/cgi-bin/ssialias?infotype=PM&subtype=XB&appname=GBSE_GB_TI_USEN&htmlfid=GBE03289USEN&attachment=GBE03289USEN.pdf.

basis, perhaps as part of an evolving platform function.[48] If energy cost and usage information becomes more transparent, customers and energy service providers can use this information to make efficient decisions to reduce their costs and increase the value of their energy systems for their specific needs.

To share data more freely to simulate a competitive market as opposed to monopoly conditions, it is often necessary to consider barriers that prevent the competitors with the monopoly enterprise, such as the DER[49] providers, from obtaining both utility and customer data which the utility has at its disposal. Because DER providers are essentially direct competitors in many cases with distribution utilities enjoying a local monopoly, these third-party clean energy technology companies view the lack of a utility incentive to easily share utility and customer data (with customer consent) as problematic. This is particularly due to the fact that this data would provide opportunities for them to offer alternative solution sets to consumers, lower costs of customer identification and acquisition, and allow DER providers to compete with utilities for certain services.[50] The need for utility performance incentives and corresponding metrics that will motivate utilities to provide data to third-party energy technology companies in order to compete in this space is essential to facilitating competitive energy services. For this reason, New York's REV has focused on addressing these issues through a DER provider survey[51] as part of its earnings adjustment mechanism. The REV DER survey is currently under development.

With the goal of encouraging enhanced data exchange, the metrics in this area generally focus on providing an indication of grid network data access by third-party providers and metrics which indicate customer ability to authorize and share

48 The New York PSC noted the evolving role of the utility and the potential platform services utilities could offer. In its Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, the PSC noted that "utilities will have four ways of achieving earnings: traditional cost-of-service earnings; earnings tied to achievement of alternatives that reduce utility capital spending and provide definitive consumer benefit; earnings from market-facing platform activities; and transitional outcome-based performance measures." This recognizes the fact that "the traditional provider's role has evolved to a platform service that enables a multi-sided market in which buyers and sellers interact. The platform [will collect] a fee for this critical market-making service, while the bulk of the capital risk is undertaken by third parties." New York PSC, Case No. 14-M-0101, Order on May 19, 2016.

49 Distributed energy resources are any resource on the customer side or premises and include passive and active resources such as energy efficiency, distributed solar, and combined heat and power generation as well as customer premises demand-response resources. Definitions vary such that DERs may also include storage or microgrids, or both, in some jurisdictions.

50 Elkind, E. (2015). Knowledge is Power: How Improved Energy Data Access Can Bolster Clean Energy Technologies & Save Money. Berkeley, California: Center for Law, Energy & the Environment. Retrieved from: http://scholarship.law.berkeley.edu/cgi/viewcontent.cgi?article=1016&context=cleepubs.

51 The DER provider survey is being developed by stakeholders to assess how well the utilities are implementing the multiple purposes of REV. The New York Commission recognized that establishing a baseline for DER deployment is particularly difficult. Rather than simply track DER interconnection requests with no way of evaluating the quality of the interconnection process, the New York Commission instead focuses its PBR for DER on a survey of DER providers. The sophisticated survey of DER providers is meant to assess how well utilities are working with DER developers on interconnections and identify targeted locations on the grid system where DER may have high value to reduce load.

data with third-party providers. Examples of metrics for data exchange include:

Third-party access metrics:[52]

- Open and interoperable smart grid infrastructure that facilitates third-party devices; and,
- Third-party vendor satisfaction with utility interaction.

Customer access to data metrics:

- Customers able to authorize third-party access electronically;
- Percent of customers who have authorized third-party access; and,
- Third-party data access at same granularity and speed as customers.[53]

Development of distributed energy resources

PBR can set incentives for greater DER penetration. These incentives are important to overcome the disincentive the utility has to facilitate DERs otherwise. While DER investments at the right places in the grid potentially reduce the need for utility investments, DERs also reduce utility sales volume which reduces utility revenue. The utility desire to build rate base and increase the volume of sales (the “throughput incentive”) give utilities two strong structural incentives to resist DERs, even in scenarios where DERs are the lowest cost resource option available. This is an example of the pervasive tension between the utility’s fiduciary duty to its shareholders and the interests of the utility’s customers. PBR and incentive rates are being explored increasingly as a way to bridge that gap and align the interests of both the shareholders and the consumer. The strong traditional incentive for utilities to build rate base and to increase sales volumes can motive utilities to resist deploying DER solutions.[54]

Depending on the goals of the jurisdiction and the level of penetration of the resources, some of the DER penetration metrics below can be structured as

52 Whited et al., 2015.

53 Whited et al., 2015.

54 Littell, D., Kadoch, C., Baker, P., Bharvirkar, R., Dupuy, M., Hausauer, B., Linvill, C., Migden-Ostrander, J., Rosenow, J., Wang, X., Zinaman, O., and Logan, J. (2017). Next-Generation Performance-Based Regulation. Golden, Colorado: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf.

tracking metrics to require periodic public reporting but perhaps not with an associated financial incentive until the precise direction a commission or legislature wants to take is clear. Tracking metrics allow the Commission and stakeholders to gather information about new resources, which can form the basis for future integrated resource or distribution plans that can make the most effective use of DER grid services. In some cases, public disclosure may suffice to motivate utilities to take certain actions in concert with other stakeholders.

Examples of metrics for DERs deployment can include:

- Number of installations per year (photovoltaic, combined heat and power, small wind, electrical vehicle [EV] charging stations)
- MW installed by type (photovoltaic, combined heat and power, small wind, etc.)
- Number of storage installations per year
- MW installed by type of storage (thermal, chemical, etc.)
- Percent of customers with storage technologies enrolled in demand response programs
- Net metering installed capacity (MW)
- Net metering MWh sold back to utility
- Net metering number of customers
- Percent customers with EVs enrolled in demand response programs[55]
- Number of third-party service providers entering the market to provide energy services.

PBR metrics for DER also can focus on location where it is beneficial to the grid to concentrate development in a certain area by concentrating DERs in a high-cost utility area (i.e., an area where short-term marginal costs of system improvements are high and DER investments may help to defer or avoid grid upgrades). Infrastructure and operational cost savings can offset utility revenue losses and make net savings available for a PBR shared savings to reward utilities for cost

[55] Whited et al., 2015.

reductions and innovation while sharing savings with customers.[56] This is perhaps most easily accomplished in vertically integrated utilities where savings from DERs in supply and utility plant accrue to the utility itself but also could be quite valuable to a distribution company. This model of sharing of location energy data can be structured in a PBR system to designate high-cost utility areas for DER development as high value. The structure of the PBR system would incent the utility to provide customers and third-party developers with data on where DERs are most desirable, i.e., have highest system value.[57]

This is what New York did with the Brooklyn-Queens Demand Management Project, where the utility provided incentives such as direct payments to DER providers or customers, direct DER investment by the utility and facilitated competitive procurements among DER providers, with payments to DER vendors capped at the utility savings, to direct DER development to a high-cost area to avoid a substation and associated infrastructure upgrades.[58] The utility was allowed to recover the costs of DER assets it acquired and also an additional ROE adder if it was successful in acquiring adequate demand-side reductions through its DER acquisition process. While this can be described as a shared savings system because there were distribution system savings of hundreds of millions of dollars, implementation occurred through an ROE adder and allowed recovery of utility costs for direct utility procurement of DER assets in a particular high-cost area. The measurable performance criteria and metrics were specific load reductions to be achieved through DER procurements by the utility contractors.[59]

Innovative products and services

One goal of the Commission is to keep abreast of innovative products. There have been numerous pilots making real time rates available to residential ratepayers. Illinois has moved beyond pilots to pioneer large-scale deployment of voluntary residential real time pricing, sometimes known as real-time rates (RTRs).

Providing an accurate price signal to customers has been an issue in many jurisdictions with traditional rates following rate structure which is more or less priced in cents per kWh for energy consumed. Because system costs vary

[56] Regulatory Assistance Project, 2000, p. 40.

[57] Littell et al., 2017.

[58] Whited et al., 2015.

[59] Littell et al., 2017.

considerably by time of day, and by season for both generating and delivering electricity, the theory is that customers will make more efficient decisions for themselves and the system if they see the relative scarcity or abundance of electricity service reflected in their price. Customers would, for instance, see that they can save money by running a large appliance on the weekend rather than during the week. However, customers can adjust their use to reflect pricing and scarcity only if the customer's price accurately reflects the cost structure of supply and utility plant during peak hours.

To make RTRs a reality for its ratepayers, Illinois required both a utility RTR option,[60] and that the monthly data interchange data be made available to competitive suppliers. The PBR aspect of this innovation is that through an agreement among Commonwealth Edison, Ameren Illinois, the Citizens Utility Board, and the Environmental Defense Fund, the utilities developed metrics to track customers enrolled in these time-varying rates.[61] This includes at least four different metrics:

- Number of residential customers on the utility tariff with time-variant or dynamic pricing in each delivery class, and reported as a percentage of customers taking supply from that retail supplier with both numbers and percentage by rate class.
- Number of residential customers serviced by retail suppliers which have requested monthly data interchange for interval data (meaning the customer's accounts will be set up for monthly data transfer of interval usage data) and reported as a percentage of customers taking supply from that retail supplier with both numbers and percentage by rate class.
- Then the same two metrics as above for small commercial customers.[62]

The Illinois reporting metrics illustrate significant interest in Illinois in ensuring

[60] Star, A., Evens, A., Isaacson, M., and Kotewa, L. (2008). Making Waves in the Heartland: How Illinois' Experience with Residential Real-Time Pricing Can Be a National Model. CNT Energy. Retrieved from: https://www.elevateenergy.org/wp/wp-content/uploads/MakingWavesintheHeartland.pdf.

[61] Environmental Defense Fund (2013). Pioneering smart grid energy metrics will help measure customer benefits in Illinois. Retrieved from: https://www.edf.org/news/pioneering-smart-grid-energy-metrics-will-help-measure-customer-benefits-illinois. See also original metrics from Commonwealth Edison Co. (2013). Smart Grid Advanced Metering Annual Implementation Progress Report. Retrieved from: http://blogs.edf.org/energyexchange/files/2013/04/ComEd-2013-AIPR.pdf.

[62] Whited et al., 2015, p. 85.

that customers have accurate pricing signals. The ICC further wants stakeholders, the public and the regulators to be able to track the enrollment of customers in these RTR options through public reporting each year.[63] The Illinois utilities also report on customer savings compared to standard offer products each year. Results have generally shown savings since implementation excepting the polar vortex in 2013-14, and Illinois has large numbers of ratepayers opting into these RTRs.[64]

6. PBR for Grid Modernization Goals

One of the areas of interest to the Ohio Commission is to enable the development of a smart grid. A modern grid strategy generally is open to customer participation on the customer side of the meter, while incenting utilities to remove barriers that impede such participation. A number of investments in grid-side modernization, such as smart grid infrastructure, distribution automation, and smart meter upgrades, may be warranted as the Commission and stakeholders further explore the goals they wish to achieve. Smart metering infrastructure, also known as advanced metering infrastructure (AMI), is a particularly important aspect of a modernized grid because combined with data management and sharing systems it enables the achievement of other goals, such as enabling customers to manage demand and take advantage of time-varying rates and determine whether to install DERs, and enables DERs to provide value to the utility system as well as customers.

Advanced meters can enable system efficiency gains and energy savings through demand response programs. The utilities' desire to install smart meters is best paired with considering (and requiring) customer benefits such as peak management programs that can result in customer rebates, or the availability of customer-friendly time-varying rate schedules that will enable them to control their energy use and save money. For example, Maryland's three IOUs have implemented peak time rebate programs for residential ratepayers utilizing their AMI.

[63] Puerto Rico Energy Commission, Order No. 8594, Article V, Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority, May 22, 2015. Retrieved from: http://cepr.cloudapp.net/wp-content/uploads/2015/09/RE-8594-EN.pdf. Other topics with subtopics include reliability, system costs and environmental goals.

[64] Elevate Energy (2015). Elevate Energy 2014 Annual Report. Retrieved from: https://www.elevateenergy.org/wp/wp-content/uploads/ElevateEnergyAnnualReport-2014.pdf.

The metrics to measure progress should be correlated with specific performance criteria. The metrics can be fairly straightforward and can be implemented initially as report-only metrics. Through EIA Form 861, regulators can track the number of customers with AMI and the amount of energy served through advanced meters.[65] Once AMI is installed, the Commission could investigate various incentive options to achieve other policy goals. For example, the number of customers on time-varying rates can be tracked in comparison to the total number of customers with state specific reporting. If only a few customers are on time-varying rates, the Commission can look first at the design of the rate as compared to the tariffs of other utilities that have reported success. The Commission can also look at the utility companies' efforts in marketing time-varying rates and ensure that marketing efforts are sufficient to reach customers with the necessary information.

For grid modernization, it is important to include reporting and then incentive mechanisms that identify possible unreasonable increases in costs, encourage timely installation, and ensure that incentive systems operate as expected. The smart-grid rollout plan the French regulator proposed for one of its largest distribution system operators addressed such elements. The performance incentive in the French smart meter implementation program awards the utility through basis points attached to assets installed through the program between January 1, 2015, and December 31, 2021. The utility is awarded bonus basis points according to a calculation that takes into account how well the utility controls investment costs and complies with the deployment timetable, and how well the smart metering system performs in meeting the objectives of the project and delivering a high quality of service.[66]

In Illinois, regulators have developed slightly more advanced performance metrics for tracking the development of the smart grid (no financial incentives or penalties are yet attached to them). These include things as simple as tracking the number of advanced meter malfunctions that disrupt customer electric service. It also includes more complex metrics such as tracking peak load reduction enabled by AMI and demand response programs.[67]

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[65] Whited et al., 2015, p. 99.

[66] More detail on this incentive structure can be found in Littell et al., 2017, p. 83.

[67] Whited et al., 2015, p. 85-86.

7. Voluntary Tracking Metrics for EV Deployment

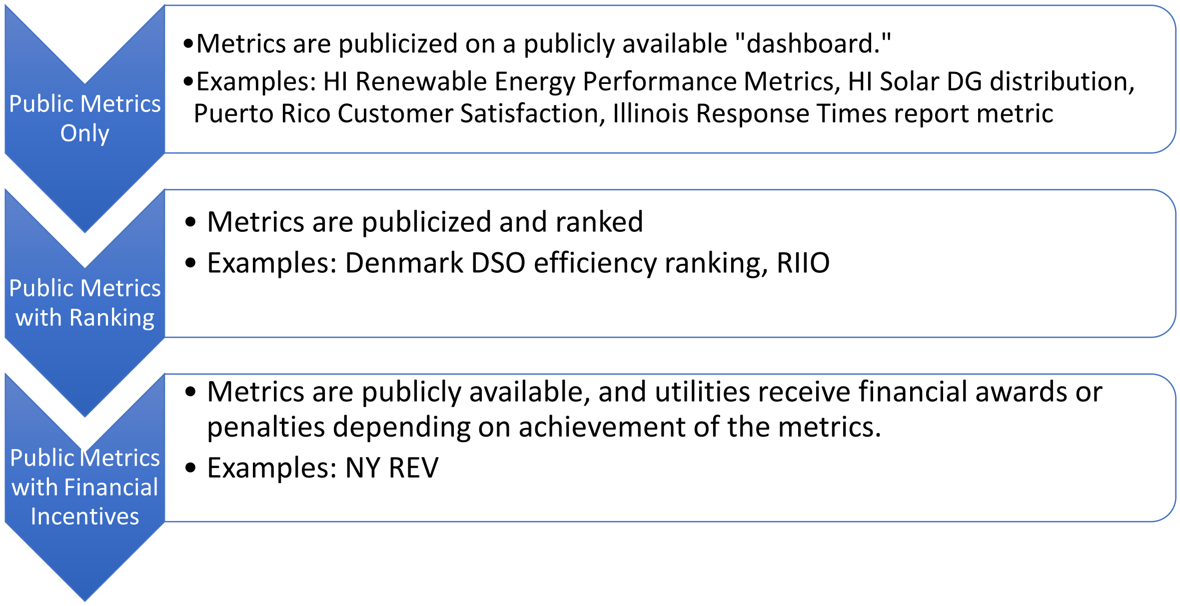
Public reporting obligations, such as tracking specific performance criteria and metrics that are important to a jurisdiction, are a way to build experience with performance metrics prior to attaching rewards or penalties. Reporting metrics allow for jurisdictions to gain knowledge on how new technologies are being deployed, or how consumers implement them where there are grid benefits and costs involved. Information that is gained from the public reporting metrics can enable regulators and other stakeholders to obtain a more complete picture of many variables associated with new technology, which can then be relied upon for future regulatory or PBR efforts.

The benefit of a public report-only metric is that regulators and utilities can implement performance metrics without attaching financial awards to gain experience and training as the performance metrics are fine-tuned. Regulators, utilities and stakeholders can examine what is important and where to focus, and ask how they are doing without focusing on obtaining rewards or penalties—at least initially. Then, after awhile regulators and utilities can ask, “If we were doing better, what is that worth?”[68]

Reporting obligations for performance criteria and metrics themselves can be a light form of PBR: a reporting requirement and metric without a positive or negative financial incentive connected with the reporting obligation. The establishment of a reporting obligation communicates the importance of that performance criteria and metric. The requirement that utilities track, analyze, and report specific information can both encourage different utility behavior, be precedent to establishing incentives, and provide transparency which may allow other stakeholders to address utility performance through various regulatory, public, or policy avenues. Figure 3 illustrates the continuum of metrics for PBR, ranging from reporting metrics made publicly available, to public reporting of metrics with financial awards or penalties based upon performance.

[68] The state of Vermont used this approach and now has utility-specific service quality plans for all utilities. Vermont Public Service Board (2016). Service Quality Plan. Retrieved from: http://psb.vermont.gov/document-category/service-quality-plan?page=1.

Figure 3: Metrics Continuum



One ripe area for tracking metrics is for EV deployment. Tracking metrics for EVs can help the Commission and stakeholders gather information not only on EV deployment levels, but also on the variety of benefits that EVs can provide to the grid or potential costs if not integrated effectively—and the metrics can identify grid costly integration. One way to think about an EV's usage characteristics is to think of EVs as mobile batteries.[69] Grid services that EVs can provide include frequency regulation, spinning, non-spinning, and supplemental reserves, and load following/ramping support for renewables.[70] EVs also have the capability to provide distribution upgrade deferral, i.e., an alternative to investments otherwise necessary to maintain adequate capacity to serve load.[71] Some jurisdictions have recognized that usage characteristics of EVs, and the technologies that they contain, allow them to function as a grid asset, "reducing operating costs for facility and vehicle owners, the utilities' distribution maintenance requirements, and energy prices in the wholesale market."[72]

[69] The descriptions of grid storage applications are based on categories of "Energy Storage Services" developed by DOE and the Electric Power Research Group. Akhil, A., Huff, G., Currier, A., Kaun, B., Rastler, D., Chen, S., Cotter, A., Bradshaw, D., and Gauntlett, W. (2013). DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA. Albuquerque, NM; Sandia National Lab. Retrieved from http://www.sandia.gov/ess/publications/SAND2013- 5131.pdf.

[70] Regulatory Assistance Project (2017). Getting From Here to There: Regulatory Considerations for Transportation Electrification. Retrieved from: http://www.raponline.org/knowledge-center/getting-from-here-to-there-regulatory-considerations-for-transportation-electrification/.

[71] Regulatory Assistance Project, 2017.

[72] Regulatory Assistance Project, 2017.

Tracking metrics on a variety of areas that affect EVs can help gather information and maintain attention on areas that might otherwise be overlooked. One of these areas is the type of charging stations that are deployed. A voluntary reporting tracking metric on the number of Level 1 and Level 2 charging stations could draw attention to an efficiency improvement that can be achieved by the type of charging station installed, as well as installation costs overall. Level 1 charging stations are ordinary household outlets. Level 2 charging stations supply 240V, like what an electric dryer or oven uses. Level 2 stations allow for a wide range of charging speeds, all the way up to 19.2 kW, or about 70 miles of range per hour of charging.[73] Figure 4 shows that Level 2 charging stations are more efficient than Level 1 charging stations. While the number is not much, it could impact peak load in a high penetration scenario. Attention to this detail in a low penetration stage can set good precedent for later buildout.

Figure 4: Summary of Level 1 and Level 2 Charger Efficiency

Charge event dataset	Average Level 2 Charge Efficiency	Average Level 1 Charge Efficiency	Efficiency gain of Level 2 charging
Total combined	86.4%	83.7%	**2.7%**
High energy only (>2 kWh charge)	86.5%	84.2%	**2.3%**
Low energy only (<2 kWh charge)	83.5%	70.7%	**12.8%**

Other EV tracking metrics that would gather useful information for the Commission and stakeholders include the following:

- Number of charging installations per year and cumulative
- Capacity (MW) of charging installations per year and cumulative[74]
- Number of EVs added to the grid each year
- Percent of customers with EVs enrolled in demand response programs
- Percent of EV customers with time-of-use rates

[73] Saxton, T. (2011). Understanding Electric Vehicle Charging. Plug In America. Retrieved from: https://pluginamerica.org/understanding-electric-vehicle-charging/.

[74] Littell et al., 2017, table 4.

- Charging load and peak moved off evening peak with time-of-use rates[75]
- Charging under the control of aggregator(s)
- Number of EV customers in areas needing distribution system upgrades

The data such tracking metrics collect can help the Commission and stakeholders understand how EVs are developing in Ohio, how they are impacting the grid, and how to determine the best way to utilize the resource they can represent.

IV. Alternative Revenue Compensation

A. Performance-Based Regulation Options

Adjustments to Rate of Return

One of the methods for providing incentives (and penalties) to utilities to motivate them to carry out the public policies established by the state of Ohio and implemented by the Commission is through adjustments to the rate of return. The Commission can establish certain goals and provide guidance to the utilities of the benefits and detriments of achieving or not achieving, respectively, the goals set forth in the performance metrics. Modifications to the rate of return measured in terms of basis point adjustments can be very granular and assigned to each metric, or the modifications to the rate of return can be more discretionary based on a full review of the utility's performance both positive and negative.

Under Ohio law, the Commission is authorized to establish "a fair and reasonable rate of return to the utility" which is based on a valuation of its property when setting rates.[76] The statute does not define "fair and reasonable" and leaves it to the Commission's discretion. The Commission also has the authority in setting rates to consider "... the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered by the public utility, the value of such service to the public, and the ability of the public utility to improve such service and facility."[77] This

[75] A reasonable assumption can be made that EV users will charge when they park their cars at a charger and not shift charging (manually or through programming the car charging software) unless given an incentive to do so. Rate trials for EV charging show this pattern of charging, mostly in the evening when returning home, unless rates encourage EV users to shift their charging.

[76] OH Revised Code, Section 4909.15 (A)(2).

[77] OH Revised Code, Section 4909.152.

section permits the commission to order the utility to improve the facility(ies); however, the Commission is required to authorize a rate of return that is just and reasonable. Again, the determination of what is just and reasonable under the circumstances is left to the Commission's discretion. The Commission also has the authority to consider a utility's management policies, practices, and organization when setting rates.[78] This section could provide the Commission with the authority to increase or decrease the rate of return based on the utility's actions to proceed with grid modernization and foster customer engagement through removing barriers to third parties, providing access to data, engaging in public education so that customers are aware of their options, and protecting privacy.

If a utility files an Electric Security Plan—as all Ohio's IOUs have—the law explicitly allows the Commission to authorize "… provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization."[79] Thus the Commission authority to authorize an incentive payment is explicit; however, such an incentive should be conditioned upon the utility's performance in encouraging customer participation in energy services.

Within the context of rate of return, the Commission could focus on the equity portion as part of the overall rate of return. Under a base ROE PBR, the utility earns a base ROE, and then that return increases or decreases based on a performance incentive structure that rewards (or penalizes) performance with modifications to the amount of return. The utility can increase its ROE through performance incentive adders up to a maximum level the Commission determines. By the same token, poor performance will decrease the overall ROE as the company will not receive incentive payments—or a minimal incentive based on performance—to raise that ROE above the baseline. The way this would work is that the Commission would assign a value range for a series of metrics, for which the utility would receive a return if it satisfies the metrics assigned. The incentives can also scale higher or lower if certain values are achieved within the specified

[78] OH Revised Code, Section 4909.154.

[79] OH Revised Code, Section 4928,143 (B)(h).

range. The adder value may vary from metric to metric based on the value the regulator assigns. A more complex option is to provide a range that provides a level of incentives for satisfying the target and a higher incentive for exceeding it. In establishing this type of PBR mechanism, a regulator may examine the following:

- What should the base ROE level be, in the event the utility meets none of the targets?
- What value range is appropriate for each chosen metric?
- How much reward should accompany each metric so that the sum total of all the metrics equals the maximum cap with the base ROE?

TOTEX Model

"Totex" is a term often associated with the PBR model in the United Kingdom and refers to total expenditures; that is, capital expenditures (capex) and operating expenditures (opex) combined in a single cost parameter. The idea behind using the Totex concept is that it can address the inherent incentive in traditional rate-base regulation for utilities to deploy capital projects, even if they are cost-inefficient, because such activities earn a return on that investment. In theory, Totex removes that incentive by creating a "win" for shareholders if the firm chooses the most cost-efficient option, even if that option is an operating expense. A cost-efficient operating expense that substitutes for a capital expense can earn an effective "rate of return." This can be through slow money treatment or some other mechanism.[80]

In the UK approximately 80 percent of utility revenue requirements are set by Totex. The balance is generally related to return on rate base (regulated asset value) including debt and equity, taxes, depreciation, and revenues associated with incentive mechanisms. The utility can recover actual costs from ratepayers (if deemed prudent) that exceed the base Totex allowance; however, a cap limits the recovery of over-expenditures

[80] Totex valuation does not directly establish allowed revenues. It must be divided into proxy capital and expense categories, called "slow money" and "fast money," respectively. Such proxies are a means to divide an aggregate Totex valuation into an efficient projected Capex (slow money) and efficient projected Opex (fast money) that is specific to the regulated firm. Note that the aggregate Totex valuation is itself a proxy, being derived from statistical analysis of data culled from all regulated firms under Ofgem's jurisdiction. Ofgem (2017). Guide to the RIIO-ED1 Electricity Distribution Price Control. Retrieved from: https://www.ofgem.gov.uk/system/files/docs/2017/01/guide_to_riioed1.pdf.

Totex Incentive Mechanism Example:

As a simplified example of how the Totex Incentive Mechanism works, suppose a distribution firm has the need to upgrade a constrained substation, due to expected load growth. The firm's business plan estimates a capital cost of expanding the substation at $12 million, but the efficient cost is $10 million [via deployment of an advanced lithium-battery storage system], and such efficient cost is built into the projected Totex allowance. [Cost-efficient firms have used the energy-storage approach, thus the statistical benchmarking process for estimating a firm's future Totex reflects such industry best practices.]

Since the $10 million investment in lithium battery storage is implicitly included in the valuation of the firm's Totex allowance, it is also reflected in the slow money portion of, and adds to the firm's projected rate base. The firm will earn a return of and on the projected $10 million through its annual depreciation expense and allowed return on rate base [Ofgem, the British regulator, will not make retrospective adjustments to rate base as long as the firm delivers its output targets; in this case, those related to addressing network expansion and system reliability].

However, the firm is savvy, and instead of deploying an advanced battery-storage system, the firm meets its output targets by deploying an innovative geo-targeted energy efficiency and demand response program, with a lifecycle cost of $5 million. The $5 million cost savings [difference between projected Totex and actual Totex] is shared with consumers through the annual *Totex Incentive Mechanism*. The firm keeps a portion of the savings at a percentage rate called the Totex Incentive Strength Rate, say 40 percent. The refund to customers is at a sharing factor of (1-Totex Incentive Strength Rate) or 60 percent. The refund is accomplished annually by adjusting rates in the year following each Annual Iteration Process (two-year delay).

The Totex approach to expenditures is one of many elements and innovations in the UK's system of PBR. Implementing a Totex model in the US may be difficult due to differences in accounting standards between the two countries. In addition, the New York commission noted in its Track 2 Order under REV that even a full adoption of a Totex model "would not remove a potential utility bias toward maximizing its own share of total system expenditures." Incentive mechanisms are needed, in addition to addressing the utility revenue recovery model, to address these broader incentives.

Treatment of Certain Types of Expenses as Capital Expenses

An alternative to a full Totex revenue recovery model is to incorporate adjustments to the balance between operating and capital expenses into other aspects of regulation. The Commission may want utilities to have a stronger incentive to undertake certain activities that would normally fall under operating expenses. For example, investing in updated computing systems may enable utilities to advance grid modernization efforts in the future, but the existing accounting mechanisms for those expenses do not give utilities a strong incentive to pursue these updates. New York is implementing something along these lines by allowing utilities to earn a return on some operating expenses that enable developments that further their policy objectives under REV. Recognizing that numerous new IT applications will be needed, the New York PSC allows utilities to enter into lease contracts for software services over an extended period of time, and to earn a return on the unamortized balance of the pre-payment. The ability to earn a return on a portion of the lease investment with a third-party provider should help eliminate bias that utilities might have toward investing in their own capital solutions to IT problems, and ultimately encourage the utility to seek the most cost-efficient solution.

Balance Between Incentives and Desired Outcome/Savings

Determining the size of the maximum incentive payment is critical in order to ensure that the value received as a result of the utility's performance under a metric exceeds the incentive payment made to it by ratepayers. Each metric will have its own achievable potential that needs to be monetized for the purpose of this analysis. Some are already monetized, for example reductions or elimination of a cost due to the utility's actions. Others are more complex, such as quantifying system savings from distributed generation and calculating the system benefits. Thus, the Commission should be prepared to do a cost-benefit analysis on the value of the metric versus the size of the incentive.

For example, the New York PSC in its REV process has allocated 100 basis points of return broadly across all earnings adjustment mechanisms as an incentive. Each utility then has earnings adjustment mechanisms set in the context of a rate case where those 100 basis points will be allocated among those mechanisms. For the allocation of basis points to each metric as proposed by the utility, it is critical to determine the potential cost of that basis point adder and compare it against the benefit.

B. Alternative Compensation Plans

Lost Revenue Approaches

As end-use customers employ more technologies—partly through current energy efficiency activities and solar rooftop adoption in Ohio, and partly through efforts the Commission may undertake as part of a grid modernization effort—the electric distribution companies (EDUs) are likely to lose more revenue. Various regulatory mechanisms, which we will discuss in more detail below, have come into use in jurisdictions across the country. They include: straight fixed/variable (SFV) rates, residential demand charges, and decoupling.

The earliest statement of policy direction on EDU rate design appeared as part of legislation passed in 2008.[81] In pertinent part, the legislation stated that an electric security plan filed by an EDU may provide for:

"... a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system."[82]

Decoupling is next discussed in Section 4928.66 of the Ohio Revised Code, wherein it states:

(D) The commission may establish rules regarding the content of an application by an electric distribution utility for commission approval of a revenue decoupling

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[81] Ohio SB 221, effective July 31, 2008. Retrieved from: https://www.lsc.ohio.gov/documents/gaDocuments/analyses127/08-sb221-127.pdf.

[82] OH Revised Code, Section 4909.143. Retrieved from: http://codes.ohio.gov/NLLXML/ohiocodesGetcode.aspx?userid=PRODSG&interface=OHCODES&statecd=OH&codesec=4928.143&sessionyr=2017&datatype=S&noheader=0&nojumpmsg=0

mechanism under this division. Such an application shall not be considered an application to increase rates and may be included as part of a proposal to establish, continue, or expand energy efficiency or conservation programs. The commission by order may approve an application under this division if it determines both that the revenue decoupling mechanism provides for the recovery of revenue that otherwise may be forgone by the utility as a result of or in connection with the implementation by the electric distribution utility of any energy efficiency or energy conservation programs and reasonably aligns the interests of the utility and of its customers in favor of those programs.

Thus, it is worth noting that in two code sections of the statute, the Legislature articulated a preference for decoupling and did not mention any other lost revenue mechanism.

On December 29, 2010, the Commission initiated a proceeding to determine the best avenue for addressing lost revenues.[83] At the time, several utilities, American Electric Power Co. (AEP) and Duke Energy Ohio already had a decoupling mechanism in place. After considering the comments of numerous stakeholders, the Commission in its Order noted "… the importance of aligning cost causation with cost recovery in order to further Ohio's policy goals of competition, increased energy efficiency and encouraging distributed generation pursuant to Section 4928.02, Revised Code."[84] The Commission held that based on the comments and the experience with SFV rates of the natural gas companies, "the rate structure that may best accomplish these policy goals is the SFV rate design."[85] As a result of this finding, the Commission encouraged the EDUs to include an SFV component in their next base rate case. The Commission further directed the staff to include an SFV rate in its staff report if the EDU did not do so.[86]

Straight Fixed/Variable Rates

In the four years since the Commission's Order on SFV was issued, there has been

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[83] Ohio Public Utilities Commission, Case No. 10-3126-EL-UNC. Retrieved from: https://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=10-3126.

[84] Ohio Public Utilities Commission, Case No. 10-3126-EL-UNC, Order on August 21, 2013, paragraph 63.

[85] Ohio Public Utilities Commission, Case No. 10-3126-EL-UNC, Order on August 21, 2013, paragraph 63.

[86] Ohio Public Utilities Commission, Case No. 10-3126-EL-UNC, Order on August 21, 2013, paragraph 64.

a lot of regulatory activity and analysis of this issue.[87] Much has been written on the topic of aligning costs with causation, which we will explore below. By virtue of how an SFV rate is designed, it cannot align cost causation and recovery. This is because an SFV rate increases the customer charge for distribution by a dramatic amount, and concomitantly reduces the volumetric component, which is the critical rate element in sending customers price signals tied to cost.

In traditional rate designs, utilities recover fixed costs in the fixed cost charge and variable costs in the volumetric charge. An SFV rate changes this by inappropriately reclassifying variable costs as fixed costs. "In accounting terms, the only truly 'fixed' costs are interest and depreciation. All other costs, including the shareholder return, associated income taxes, labor, and revenue-sensitive costs, are technically variable costs—they change from month to month and from year to year. Utilities often define 'fixed costs' very loosely, including these other costs, as well as all distribution costs and sometimes even some generation-related costs in this category."[88] Thus, the SFV rate is based on a false premise in terms of allocating costs to the appropriate category of charges. Doing so provides the utility with increased revenue stability, but it penalizes small users and those engaged in energy efficiency and conservation, as we will discuss below.

By increasing the customer charge and decreasing the volumetric component, customers will experience a smaller increase in rates from high volume usage. On the other hand, customers who decrease their usage through conservation will receive a smaller amount of savings than they would under a traditional volumetric rate. This diminishes the incentive to conserve energy. By the same token, the incentive to purchase more efficient products, such as an Energy Star washing machine, is also reduced because of an increase in the payback period to recover the additional investment cost. Customers also get the false sense that they can use as much electricity as they want, because the incremental increase in their bill is marginal. From an economic standpoint, this does not send the appropriate price signal that increased usage will result in increased costs. If the volumetric charge is

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[87] For example, a report prepared for Consumers Union found that between September 2014 and November 2015, of the applications filed for SFV, 41.2 percent were rejected, 33.3 percent were scaled back, and 25.5 percent were approved, demonstrating a growing trend away from SFV. Whited, M., Woolf, T., and Daniel, J. (2016). Caught in a Fix: The Problem With Fixed Charges for Electricity. Cambridge, Massachusetts: Synapse Energy Economics. Retrieved from: http://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf.

[88] Lazar, J. (2015). The Spector of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power. Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/appendix-d-smart-rate-design-2015-aug-31.pdf

less than the long run marginal cost, then customers will behave as if their incremental usage has less of a cost effect than it does. This can result in greater customer usage, which means utilities need to invest in more facilities, hence raising rates.

From a small user perspective, an SFV charge with its high upfront costs can increase smaller users' bills, while a high-use customer will get the benefit of a smaller overall bill. Moreover, there is a correlation between usage and income in that low-income customers tend to use less electricity than high-income customers.[89] This stands to reason, given that high-use customers tend to have more electric gadgets than low-income customers, ranging from the number of flat screen televisions in the home to the number of electric toothbrushes. Thus, low-income customers can actually end up subsidizing higher-use, higher-income customers under an SFV rate.

Another point to consider is the impact on the elasticity of demand. Ohio has an Energy Efficiency Resource Standard, the cost of which is included in rates. If, at the same time customers are spending money through their rates to finance energy efficiency, electric usage increases under an SFV, those energy savings from the Commission-approved programs will be eroded because the price signals are not alerting customers to the need to be more energy-efficient.

Finally, if the goal of an SFV is to ensure an appropriate level of revenues, a high fixed charge which penalizes customers with distributed generation may hasten customer decisions to exit the grid altogether, thereby adversely impacting the utility's revenue levels and leaving remaining customers to make up the shortfall.

Residential Demand Charges

Of late, attention has focused on demand charges as an alternative to the traditional volumetric rate design or SFV rates. Back in the late 1970s and early 1980s, Ohio Edison Co. employed demand meters for residential customers. However, since that time, all the rate designs for the electric companies have been predominantly under a two-part rate structure consisting of a fixed monthly customer charge that recovers the cost of connecting to the grid and serving that individual customer, and an energy charge to recover all other costs. Demand

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[89] Colton, R. (2002). Energy Consumption and Expenditures by Low-Income Households. The Electricity Journal, 15(3).

charges have historically and appropriately been used for commercial and industrial customers.

Demand charges usually result in a three-part rate that includes a customer charge, a volumetric charge, and a third category of demand charges, which measures and charges customers based on their maximum rate of consumption in a monthly period. In considering demand charges it is important to analyze the goal of imposing such a charge. A number of utilities are seeking approval to implement demand charges as a means of recovering actual or potential reductions in sales, revenues, and costs. More than 30 utilities in the United States, including some rural cooperatives, are offering demand charges as an option.[90] It is not mandatory in any jurisdiction at this time.

If the motivating factor is to account for potential lost revenues, the Commission may want to consider other options such as decoupling or MRPs. If the purpose is to align cost with causation, then demand charges do not accomplish this objective. Demand charges fail to provide actionable price signals to small consumers without investment in demand control technologies or very challenging household routine changes. This results in effectively adding another mandatory fixed fee to residential customers' electric bills. Moreover, to avoid high demand charges, customers could end up altering their usage from the times of their individual maximum demands to times of high system loads and costs because there is no correlation between customer usage and utility system peaks.[91]

Among the major concerns with residential demand charges are that customers will not understand it and not know how to manage usage in order to avoid large bill impacts; and the times of peak residential usage are not coincident to utility peaks. For example, a typical residential household may have its highest single use in the morning while family members are getting ready for work and school. During that time period, hot water heaters are being used for showers, along with coffee makers, hair dryers, radios, televisions, stoves, microwaves, electric razors, and electric toothbrushes. This high usage point occurs during an off-peak time period when the utility's cost to serve its customers is low. Moreover, residents of

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90 Faruqui, A., and Warner, C. (2017). A Walk on the Frontier of Rate Design. The Brattle Group. Retrieved from: http://files.brattle.com/files/5600_a_walk_on_the_frontier_of_rate_design.pdf.

91 Lazar, J. (2016). Use Great Caution in the Design of Residential Demand Charges. Natural Gas & Electricity, 32(7) Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/lazar-demandcharges-ngejournal-2015-dec.pdf.

apartment buildings can be especially disadvantaged because utilities serve the combined diverse demand of multiple apartment units in that building as opposed to the individual apartment unit. Thus, there is no way to fairly measure the demand of an individual customer.

An inherent unfairness can result if a customer uses a sizable amount of electricity at one time of the day which is off peak, but overall has a moderate amount of energy consumption in the course of a month. Compare the bill impact on that customer to a customer who consumes much more electricity during the course of a month and whose usage is spread relatively evenly including during peak times. The latter customer could be contributing more to system costs while paying less.

For Ohio to adopt demand charges, especially on a mandatory basis, the state would need to embark on an extensive education campaign so customers understand how to moderate their electric usage to avoid large bill impacts. This is because demand charges are complex, difficult for small consumers to understand, and not likely to be widely accepted. Customers need to understand that they cannot use multiple electric devices at the same time, and even if they do, they do not have enough information to understand what the potential bill impact will be in any given month. And, if the program were successful in educating customers—a daunting task—it would not achieve the goal of addressing lost revenues. Moreover, in areas without smart meters, it would be necessary to invest in demand meters, which would need to be factored into the cost-benefit analysis of any decision to move toward demand charges.

Should Ohio want to experiment with demand charges, it might want to consider doing so as a voluntary opt-in rate along with offering a time-of-use voluntary opt-in rate.[92]

Decoupling

Decoupling is the only mechanism that addresses utility lost revenues and sends the appropriate price signals by retaining the traditional volumetric portion of the rate. Decoupling works by separating sales from revenues so the utility can recover its lost revenues irrespective of a reduction in sales. The goal is to make utilities

[92] For more on rate design, including smart rates, see Lazar, J., and Gonzalez, W. (2015). Regulatory Assistance Project. Smart Rate Design for a Smart Future. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

indifferent to their sales levels so they are free to support energy efficiency and distributed generation resources. In Ohio, AEP and Duke Energy[93] both have decoupling mechanisms, whereas FirstEnergy and Dayton Power and Light use a lost revenue adjustment mechanism.[94]

With decoupling, the utility's revenue requirements are established in a distribution rate case which then frames how to recover the revenues. At the end of an agreed-upon period (in Ohio it is done annually), a calculation measures the utility's authorized revenue requirements against actual revenues. Rates are then reconciled to allow the utility to recover (positive or negative) the difference between revenues authorized and revenues received. A simplified decoupling mechanism is illustrated in Table 6 below:

Table 6: Periodic Decoupling Calculation

Periodic Decoupling Calculation	
From the Rate Case	
Target Revenues	$10,000,000
Test Year Unit Sales	100,000,000
Price	$0.10000
Post Rate Case Calculation	
Actual Unit Sales	99,500,000
Required Total Price	$0.1005025
Decoupling Price Adjustment	$0.0005025

The benefit for the utility is that it provides the opportunity to earn a pre-determined level of distribution revenue regardless of the actual amount of energy sold. This enables utilities to project cash flow more accurately and avoid much of the earnings volatility from changes due to policy goals (and other influences such as weather and the economy) that occur under traditional regulation. Further, it

[93] Ohio Public Utilities Commission, Case No. 11-351-EL-AIR and Case No. 11-5905-EL-RDR.

[94] A lost revenue adjustment mechanism (LRAM) requires the calculation of the reduction in sales resulting from a utility energy efficiency program. The number of kWh reductions is then multiplied by the appropriate rate to determine the lost revenue amount. This can get litigious, with stakeholders holding different views on the calculation of those savings based on the success of the program. Moreover, the LRAM methodology does not reduce the incentive for the utility to continue to try to increase sales while simultaneously offering energy efficiency ƒƒprograms. These inconsistent activities can have the effect of diminishing the impacts of the energy efficiency programs, which are designed to reduce system energy demands.

reduces the need for rate case filings, lowering overall costs for the utilities.

A benefit for customers is that, unlike SFV, in which the utilities retain any excess earnings, decoupling ensures that the utility will recover its revenue requirements and nothing more. Under an SFV rate the utility earns its revenue requirement only if it meets the number of customers used to set the revenue requirement and there are no changes in the sales level per customer. Otherwise, a utility under an SFV will have more or less revenue requirements depending upon whether there is customer growth or decline. The latter would be the same for a per-customer decoupling scheme like the one used in Ohio. Under both SFV and decoupling scenarios utilities can experience additional earnings if they lower their costs below their approved revenue requirements.

Under Ohio law, utilities may include in their electric security plan (ESP) provisions for cost recovery of a long-term energy delivery infrastructure modernization plan. Most utilities have filed distribution rate cases which serve as a good venue for implementing a decoupling mechanism. The exception is FirstEnergy, which has chosen to use the ESP mechanism to address the recovery of distribution costs. The law states that if the utility is deemed to have garnered significant excess earnings during the term of the ESP, the Commission can adjust rates.[95] A decoupling mechanism could protect distribution customers from any excess earnings.

No two decoupling mechanisms are alike. There are a number of decision points that enable the Commission, with input from stakeholders, to design a decoupling mechanism that best meets the needs of the state. These decision points are discussed below.[96]

A. **Applicability of Utility Function—**Since Ohio is deregulated, the decoupling mechanism should apply only to distribution rates. However, should Ohio go back to re-regulation, as some utilities are advocating in the Legislature, then the Commission would need to decide if decoupling should apply to generation as well.

[95] OH Revised Code, Section 4928.143 (F).

[96] For more information on these design choices and case examples of how utilities have designed decoupling mechanisms, see Migden-Ostrander, J., and Sedano, R. (2016). Decoupling Design: Customizing Revenue Regulation to Your State's Priorities. Regulatory Assistance Project. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/11/rap-sedano-migdenostrander-decoupling-design-customizing-revenue-regulation-state-priorities-2016-november.pdf; and Regulatory Assistance Project (2016). Revenue Regulation and Decoupling: A Guide to Theory and Application. Retrieved from: http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf.

B. **Applicability of Revenue Regulation to Customer Classes—** Generally speaking, decoupling always applies to residential customers, but some jurisdictions exclude industrial customers. The rationale is that residential customers are a more homogenous group, making the decoupling adjustments easier to determine, whereas it is more complex with industrial customers who have demand charges in addition to energy charges.

C. **Costs Included in a Decoupling Mechanism—**The decision point here is whether to apply the decoupling mechanism only to base rates or also to some or all riders. If actual costs are adjusted separately and periodically under a rider, they probably should not be included in the decoupling mechanism as it could result in double recovery of some costs. RAP generally recommends that the decoupling mechanism apply only to base rates.

D. **Frequency of Rate Cases to Adjust Revenue Requirements—** Options include requirements for periodic rate cases such as every three to five years; allowing the utility to determine when its wants to file for a rate case to adjust revenues; or mini or full annual rate cases.

E. **Ex Ante Adjustment to ROE/Capital Structure—**Some consumer advocates argue for a reduction in the ROE to recognize reduced risk from a somewhat guaranteed revenue requirement. This is controversial in that utilities generally oppose this. Another option is to recognize that because of the reduced risk the utility can increase its debt due to decreased risk, under the debt/equity capital structure, which will produce customer savings without penalizing the utility.

F. **Revenue Adjustment Mechanism (RAM)—**This is probably the most significant design decision, and there are a number of options:

   I. No RAM—There is no adjustment to the revenue requirements. Rates remain unchanged until the next rate case.

   II. Stair-Step—These are predetermined adjustments made in the last rate case based on forecasts of projected cost increases.

   III. Indexing—Adjustments to the revenue requirements are tied to factors such as inflation, industry productivity, and customer growth.

IV. Revenue Per Customer—The revenue requirement is determined on a per-customer basis and is adjusted for the total number of customers served. This is perhaps the most common adjustment, and Ohio has used it in its decoupling mechanisms.

V. Annual Review Decoupling (aka Attrition Decoupling)—Periodic rate adjustments reflect incremental and decremental known and measurable changes to rate base and operating expenses.

VI. K Factor—This is an adjustment used to increase or decrease overall growth in revenues between rate cases. For example, a K Factor can reflect declining costs between rate cases due to depreciation of assets.

VII. Hybrid—This allows regulators to combine various RAM mechanisms to adjust rates.

G. **Refunds and Surcharges—**This decision reflects whether in addition to including a surcharge for any unrecovered revenues, the utility is also obligated to credit any over-recoveries to customers to create symmetry in the adjustment mechanism. RAP recommends requiring symmetry so that the utility recovers its annual revenue requirements in accordance with the RAM, no more or less.

H. **Allocation of Any Over- or Under-Recoveries—**Options include by customer class, across the board, or by rate element. An allocation by customer class would go only to classes included under the decoupling mechanism. In an across-the-board allocation, regulators may consider customer contribution to total load as opposed to applying the same kWh charge across all classes. The rate element allocation has not been used much, but the design could, for example, allocate refunds to the first tier of inclining block rate, while allocating surcharges to the second tier. This would help low users and serve as a small conservation incentive.

I. **The Revenue Adjustment Mechanism—**The RAM can be handled through a rider or in base rates. Ohio uses a rider currently, which, given Ohio's mechanisms for establishing rates, makes the most sense.

J. **Frequency of True-Ups—**States can use either an accrual method, with adjustment made up to one year, or the monthly method. Ohio, like most states, currently uses the accrual method.

K. **Caps on the Size of the Adjustment Mechanism—**Some states favor a cap to protect customers and utilities by limiting the size of a potential rate increase or decrease, respectively. These can be expressed as a percentage increase in rates or revenues or as a dollar value. Rate adjustments generally fall within plus or minus 3 percent, with the bulk being between plus or minus 1.5 percent.

L. **Carrying Charges for Deferrals—**This can be applied if the accrual method is used and utilities are carrying costs on their books for up to one year or to any deferrals due to the cap on the size of the adjustment, or both. Typical deferral rates include the weighted average cost of debt or the customer deposit rate.

RAP's opinion is that a decoupling mechanism is the best regulatory option for addressing lost revenues and assuring that customers receive the appropriate price signals with respect to their usage. Moreover, of the options discussed above, decoupling is the only mechanism that aligns cost causation with cost recovery.

V. Conclusion

The Commission has convened an inquiry to examine modernizing the electric grid and to explore what that would entail. Grid modernization can provide many benefits and is the next step in the evolution of energy service delivery. The state of Ohio has already restructured the energy industry to allow retail choice. This has opened to door to aggregation and the offerings of many suppliers, offering fixed and variable products as well as renewable energy. With grid modernization comes the opportunity to expand these services in an interactive manner in which customers not only purchase services but can supply them to the grid to make the grid more efficient and cost-effective. These services can include demand response to manage the peaks and valleys and help integrate more renewable energy and ancillary services. It can also help facilitate the integration of EVs and storage products to benefit the system as a whole, and thereby, benefit the utilities and their ratepayers. But the value of grid modernization extends beyond opening the electric market to more choices for customers who seek value-added services. It can create a more resilient grid, better able to withstand turbulent weather events, and provide reliable vital services.

The key question is how to transition to the modernized grid. The answer lies in part in reforming the traditional regulatory paradigm so as to enable utilities to make changes that align the public interest with those of their shareholders to whom they owe a fiduciary duty. The Commission can take many steps on an incremental basis that will enable it and stakeholders to garner information and measure progress during the transition.

This paper has offered an analysis of a number of potential steps as the Commission wades into the waters of change toward a stronger energy future. The recommendations from this analysis for the Commission's consideration are as follows:

1. In the immediate short term, create reporting metrics that include measures for which the Commission desires to see improvement, the appropriate metrics by which to evaluate the measures, the baseline from which to measure progress, and the target the Commission would like the utility to achieve.
2. In the longer term, once there are some data, the Commission can consider assigning a value through an incentive or penalty, or both, to some of these measures.
3. Choose metrics that are in keeping with the Commission's goals. This paper discussed a number of potential metrics addressing reliability, safety, consumer protections, efficiency for the grid system and on the customer side of the meter, the encouragement of third-party services through data access, opportunities through rate design and demand response programs to reduce peak demand, and the development of DERs.
4. Create a transparent process, with all utility reporting posted on the utility and Commission webpages for the public to view.
5. Remove the utility throughput incentive so they are indifferent to reductions in sales by implementing decoupling as discussed above.

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The Regulatory Assistance Project (RAP)®
Belgium · China · Germany · India · United States

50 State Street, Suite 3
Montpelier, Vermont 05602
USA

1 802-223-8199
info@raponline.org
raponline.org