Guidehouse

Electricity Regulation for a Customer-Centric Future

Survey of Alternative Regulatory Mechanisms

Prepared for EEI

2Q 2020

guidehouse.com/esi

Table of Contents

List of Figures

List of Tables

Executive Summary

The electric industry is in transition, driven by several key factors—from technological innovation and ambitious policy goals to the proliferation of renewable resources and the adoption of distributed energy resources (DER). Customers are playing a key role in this transformation as their preferences evolve and as they demand new and different services from their electric companies. This comes in part from a shift in consumer expectations in other industries, whether it be media services (Netflix), lodging (Airbnb), or retail (Amazon). The common thread in these industry shifts is the availability of new digital options, with customer-centric thinking at the center of success.

Regulators and legislators are increasingly acknowledging that the factors driving this energy transition are of sufficient breadth and magnitude. The traditional regulatory framework must continue evolving to enhance the ability of electric companies to meet customer expectations while maintaining a grid that is affordable, as well as reliable and resilient. Alternative regulatory approaches are seeing a resurgence to meet these challenges.

This report provides a survey of alternative regulatory mechanisms that have emerged as tools to respond to evolving customer needs and expectations and to changing technological, policy, and market conditions. Each alternative regulatory mechanism discussed here has advantages and disadvantages.

It is also important to acknowledge what this report is not. It is not a roadmap for the industry, nor is it advocating for the adoption of alternative regulation. The US electric industry is diverse in all respects—in its market structure, generation profile, natural resources and geography, and customer size and segment. The path forward for the electric industry is unlikely to be uniform and will depend on the specific characteristics of each jurisdiction. As a result, the alternative regulatory approaches discussed in this report cannot and will not apply universally. In some parts of the country, traditional regulation is functioning well. In other areas, alternative regulation may be attractive. Where alternative regulation is reasonable to consider, this report offers a compendium of options—options that are being tested and applied and refined and revised—based on experience and outcome.

Although these alternative mechanisms can overlap, they may be grouped according to three categories:

- **Revenue adjustment mechanisms** focus on the manner and mechanics by which an electric company's target revenues are determined, collected, or adjusted over time and include policy tools that shift regulation away from an historic focus on costs and sales to a more prospective approach that incents and rewards cost control that ultimately benefits customers.

- **Performance mechanisms** provide focused incentives for an electric company to reach performance targets aligned with policy and customer priorities through public metrics or scorecards, or more overtly through financial rewards for achieving certain levels of exemplary performance.

- **Other regulatory mechanisms** include those that provide electric companies an opportunity to earn revenue from the procurement of cost-effective, third-party solutions to deliver products and services that support the energy transition, such as cloud-based computing or aggregated DER.

The collective goal of alternative regulation is threefold: 1) deliver customer value; 2) maintain focus of safety, reliability and affordability; and 3) align the interests of all stakeholders (customer, electric company, shareholder, and regulator). This report assesses mechanisms and approaches based on these three goals, as progress in the electric system cannot be achieved without considering the impact on the customer, the continued safety and security of the grid for all, and the impact on all parties involved in electric industry decision-making.

1.0 Introduction

Traditional cost of service regulation (COSR) was created to regulate electric service with the presumption that the electric company provided all forms of electric service across the entire value chain: generation, transmission, and distribution. Electric companies were afforded the opportunity to earn a regulated profit in exchange for accepting the financial risk of continued capital investment and accept the requirement to serve all customers. This arrangement is known as the regulatory compact. As part of this paradigm, most common rate designs operate to recover the largely fixed costs of the electricity system through mostly volumetric rates. In recent years, however, electricity demand has been flat or declining, due in large part to increased energy efficiency measures and, to a lesser extent, distributed energy resource (DER) growth. Going forward, volumetric rates may challenge electric companies' ability to make investments in the distribution grid needed to meet customer expectations about reliability, resiliency, and DER integration.

Additionally, traditional COSR has evolved in light of electric market restructuring in some jurisdictions, which separated generation, transmission, and distribution from the traditionally vertically integrated electric company, and created new business models and structures focused on individual segments of the electric company business: transmission, wholesale generation, retail supply, and electric distribution. Similarly, customer-sited resource (DER) deployment is growing—a change that often highlights challenges in the current regulatory transformation. While some DER can offer the potential to serve a range of customer loads and realize efficiencies for both the customer and the broader electric system, the traditional regulatory regime is not set up to leverage DER to their maximum potential.

One of the goals of COSR is to provide electric rates that allow electric companies a reasonable opportunity to recover the costs incurred to provide general service, including a fair ROI. An electric company realizes earnings through a rate of return on its capital investments, provided the regulator finds those capital investments were just and reasonable. Because earnings opportunities are tied to capital investments, the degree to which COSR encourages electric companies to increase their asset base to achieve consistent ROI is another factor when considering alternative regulatory mechanisms. These alternative mechanisms can tie returns to achieving multiple future energy goals while maintaining reliability and resilience. Alternative regulation can create different incentives for electric companies, but it is critical to acknowledge that continued capital investment will be necessary to achieve the goals of any future energy system.

Other realities of the changing energy landscape may encourage regulators and electric companies to consider alternative regulatory mechanisms to create earning opportunities for supporting public policy goals or responding to customer interests and priorities. Traditional incentives do not permit electric companies to capture much, if any, of the monetary value gained from meeting customers' needs through non-traditional but more cost-effective solutions. Additionally, electric companies can be discouraged or prohibited from pursuing new, more innovative energy solutions, if traditional options are the same or slightly lower in terms of initial cost. Finally, although cost containment has been a long-standing priority of COSR, new needs and opportunities may prompt a reconsideration of how best to incent cost control.

The activities and investments that provide an increasingly decarbonized, distributed, and digitized electricity system may not be well-addressed by COSR—although it is worth noting that modifications to COSR do allow for management of these modern challenges. In many environments, the traditional regulatory framework, which was designed to foster investment over 100 years ago, is no longer well-aligned to meet all the needs of modern customers or their changing expectations for electric companies. Tasked with enhancing customer solutions and achieving public priorities, many regulators have sought to employ alternative policy tools that help bring aspects of COSR into better alignment with changing customer expectations and needs.

This report identifies alternative regulatory mechanisms that are being tested and applied across the US. It also outlines how various mechanisms have been used in combination with new tools and approaches to create space for innovation and incent electric companies to meet policy goals and customer objectives.

2.0 Survey of Alternative Regulatory Mechanisms

Alternative regulatory mechanisms are aimed at helping electric companies achieve (and account for) various goals associated with shifts in the energy landscape. Many of these mechanisms can be considered components of solutions to address the evolution of the traditional cost of service model to a regulatory framework that can respond to evolving customer preferences, as well as changing technological, policy, and market conditions. While these alternative mechanisms can overlap, they may be grouped according to three broad categories:

- **Revenue adjustment mechanisms** focus on how an electric company's target revenues are determined, collected, or adjusted over time, and include policy tools that shift regulation away from a backward-looking focus on costs and sales to a more forward-looking approach that incents cost control and rewards electric company performance.
- **Performance mechanisms** provide focused incentives for an electric company to reach performance targets aligned with policy and customer priorities through the public display of metrics or scorecards, or more overtly through financial rewards for achieving certain levels of exemplary performance.
- **Other regulatory mechanisms** include those that provide electric companies an opportunity to earn revenue from the procurement of cost-effective, third-party solutions to deliver products and services that support the energy transition, such as cloud-based computing or aggregated DER.

2.1 Revenue Adjustment Mechanisms

This section highlights several revenue adjustment mechanisms. This list is not exhaustive, and the individual mechanisms are not necessarily appropriate for every jurisdiction. The best regulatory mechanism is the one that meets the particular needs of company and its customers.

- **Forward Test Year:** A method of setting an electric company's revenue requirement (revenue needed to cover the cost of service) on a forecasted basis, rather than being limited to using historical, actual costs (historic test year). A forward-looking approach reduces regulatory lag, helps to more accurately assess system needs in response to big shifts in customer behavior and to plan investments in new technologies that have not been commonly used or approved in the past.
- **Cost Tracker:** An accounting mechanism that includes some predefined level of cost recovery into a revenue requirement. This level is tracked and, with future rate reviews, adjusted based on actual costs incurred.

- **Lost Revenue Adjustment Mechanism (LRAM):** A mechanism that ensures electric companies do not see revenue erosion whole for short-term losses in base rate revenues often due to their demand side management (DSM) programs.
- **Revenue decoupling:** A mechanism that unlinks the connection between electric company revenues and sales growth, which in turn reduces companies' incentive to grow energy sales. This removes structural barriers to the adoption of energy efficiency programs or anything that would, under traditional ratemaking, erode revenue based on less volumetric throughput.
- **Multiyear Rate Plan (MRP):** An extended fixed period of time without general rate reviews in which an electric company's revenue requirement is set for multiple years (typically 3-5 years). Less frequent rate reviews can incentivize increases in electric company operational efficiencies, the benefits of which can be shared with customers and reduce administrative burden, freeing up regulatory resources to focus on strategic policy goals while enhancing value for customers.
- **Formula Rates:** An alternative regulatory mechanism that automatically adjusts an electric company's rates based on any changes to agreed-upon costs, ensuring that the electric company receives the authorized rate of return on agreed-upon investments. Similar to MRPs, formula rates can reduce administrative costs of pursuing frequent rate changes via traditional rate review filings.
- **Earnings Sharing Mechanism (ESM):** A mechanism that serves to share amounts of electric company earnings that deviate substantially from the level of earnings determined to be reasonable in setting electric company revenues and rates. The shared revenues often return to customers in the form of reduced rates. When implemented in a symmetrical manner, ESMs can serve as guardrails, maintaining the incentive for electric company performance, while giving regulators confidence that implementing performance-based mechanisms will neither harm an electric company's financial integrity nor negatively impact customers by permitting an electric company to over-earn.

2.1.1 Forward Test Years

Rate reviews use revenue requirements (the revenue needed to cover the cost of service) and billing determinants (such as the volume of energy delivered) to set the rates for upcoming years. This rate setting is done using the concept of a test year to calculate future rates. The test year allows comparison of a defined period's total rate base costs, including OPEX, with its total revenues from electricity sales.

Traditionally, this test year is historical; future rates are set using actual revenue requirements and billing determinant data from a year prior to the year of the rate review, an approach known as an historic test year. In contrast, a growing number of states have begun using a forward test year approach in which detailed forecasts of expenses and sales are used to set the new rate. In between forward and historical test years is the option of a partially forecasted test year in which some months of historical data on electric company operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate review.

The historic test year is based on actual investments, actual expenses, and actual sales of the electric company for a recently completed 12-month period. The basis of the historic test year approach is that productivity should offset inflation and therefore the total costs next year should not be materially different from the total costs last year. While this maxim may have largely held true in the past, increasingly, flat or declining sales coupled with new technologies and ambitious policy goals have given rise to a more dynamic electricity system where the historic test year is inadequate because what happened last year is a poor indicator of what will occur next year.

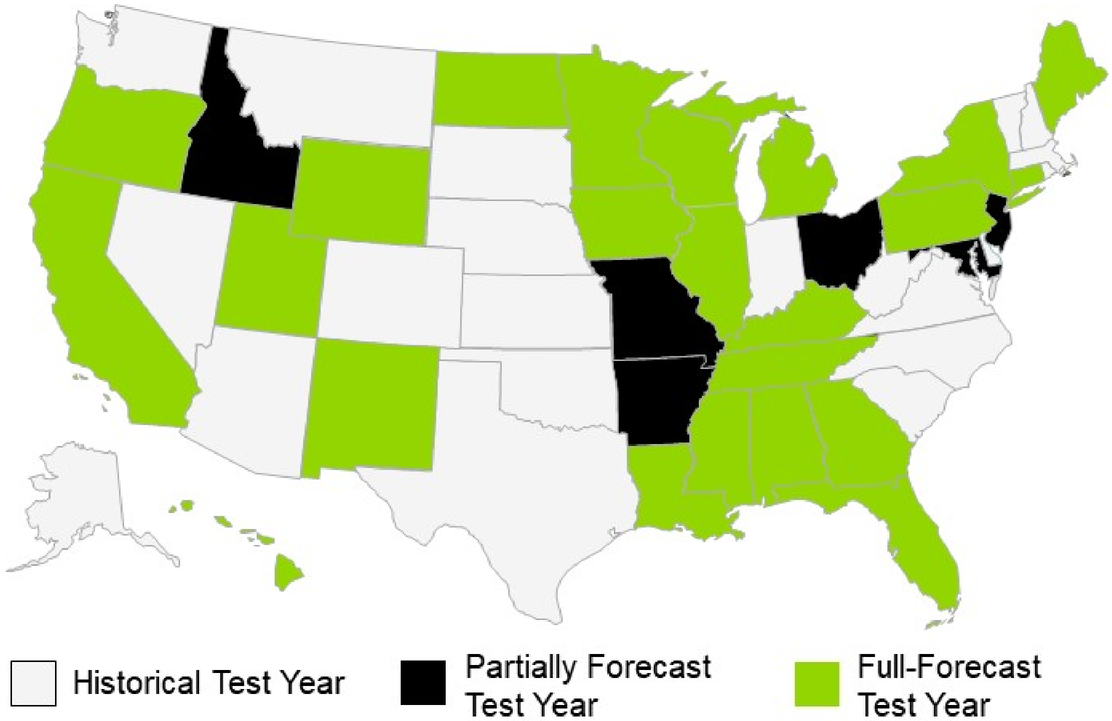
Before the early 2000s, electric company revenues largely grew faster than expenses. Today, new levels of energy efficiency and distributed generation are flattening revenues, costs are rising for retrofitting and modernizing electric company systems, and changes are accelerating. The historic test year approach cannot keep up with the rapid pace of change because it captures an estimate of costs at least a year and more likely 18 months behind the time that rates ultimately go into effect. Such an approach erodes the ability for an electric company to collect appropriate revenues on a timely basis going forward because rates are being determined on what happened in the past, not what is happening in the present. This can harm customers by acting as a barrier to modern grid investments in the near-term and by introducing the potential for future rate shock, sharp increases to customer rates as the historic test year window catches up to present day expenditures.

By forecasting conditions, forward test years can fully compensate electric companies when cost growth exceeds growth in billing determinants. The forward test year approach requires the electric company to demonstrate to regulators and stakeholders that the rate review forecast, based on the forward test year approach, is a reasonable proxy for actual costs. Accordingly, regulators, stakeholders, and customers in a forward test year environment benefit from transparency about where and how the electric company is planning on investing money.

Industry experience has shown that where the forward test year approach has been used, it has increased rate gradualism by allowing more modest increases each year rather than larger increases every few years, leading to less rate shock for customers. Various consumer protections, such as true-up mechanisms, can be incorporated into a forward test year approach to guard against inaccurate forecasts. Regulatory rules that include decoupling of electricity sales from electric company profits and annual updating of an electric company's rate of return can resolve much of the uncertainty that causes some stakeholder uneasiness with the forward test year approach.

Forward test years are used by nearly half of the states, with some always using forward test years while others only occasionally use this policy tool. For some regulators there is reticence with forward test years because of a fear that the revenue requirement could be overstated, and electric companies could over-earn; however, the number of states and years of using this process has led to a set of controls and best practices to protect customers. Figure 2-1. provides an overview of adoption of forward test years in the US.

Figure 2-1. US Forward Test Year Prevalence by State: 2019



Source: Guidehouse

2.1.2 Cost Trackers

A cost tracker is a mechanism for the expedited recovery of specific electric company costs that fall outside of base rates. Balancing accounts are often used to track unrecovered costs that regulators deem prudent. Cost recovery is often implemented using tariff sheet provisions called riders.

A cost tracker helps an electric company recover specific costs more quickly, especially for costs such as purchased fuel, costs stemming from outages caused by extreme weather, and costs of compliance with new policies and regulations, such as energy efficiency standards or environmental upgrades. All of these costs are outside the electric company's control and cannot be added into base rates ahead of time; however, they can lead to regulatory lag[1] if the company must wait to recover costs through its next traditional rate review. To ensure protection of customer interests, cost trackers are often used only for specific costs that meet certain parameters (e.g., outside of an electric company's control) and have undergone an intensive review by the regulatory commission.

Cost trackers, especially for capital investments, are often approved in advance of the investment and the cost is recovered through a specific line item on customer bills. An early use of cost trackers was for large construction projects, allowing a cost tracker for construction work in progress to reduce financial strain on the electric company due to multiyear construction projects and the inability to recover costs until the project was in service, as well as reduce rate

[1] Regulatory lag is the difference between the time when a utility's costs increase and when the utility can raise its rates in order to recover revenues equal to those costs.

shock to customers after the project is finished. Cost trackers are now commonly used for fuel and purchased power, severe storms, uncollectible bills, pensions, and healthcare. Cost trackers can also be used to address costs incurred from changes in government policy such as certain taxes. In recent years, cost trackers have been adopted to address costs for emissions controls, generation capacity, advanced meter infrastructure, and general system modernization.

If spending on a tracked cost is above or below the preapproved budget, the true-up process between costs and revenue can vary. Some cost trackers have no balancing activity, meaning that any extra expenses the electric company incurs must be covered by the electric company itself and not by customers, or there can be a sharing mechanism in which the electric company and the customer share either the excess cost or savings. Finally, the difference in costs and revenue for the investment and rider can be balanced completely using a true-up mechanism.

Cost trackers can add value to the regulatory framework by isolating certain categories of expenditures that do not need to be contested or heavily deliberated within each new rate review since they have already gone through an intensive prudence determination with the state regulatory commission. This streamlining can help provide clarity and certainty to the market, lowering costs to customers.

Cost trackers are the most widely used alternative regulation tool in the US. For example, when the Pennsylvania Public Utility Commission (PUC) required Pennsylvania electric distribution companies to implement a smart meter plan in 2008, the same act established a cost tracker to cover all costs incurred to procure and install the smart meter system.[2] This cost recovery is displayed on customer bills as a rider, or separate line item on the bill, that adjusts in reaction to any changes in the cost to implement advanced metering infrastructure (AMI).

2.1.3 Lost Revenue Adjustment Mechanism

By implementing DSM programs, electric companies operating in a traditional regulatory environment would likely experience a decrease in electricity sales, which in turn would likely result in the under collection of requisite revenue. Absent a correction to this structural challenge, electric companies may find it difficult to support ambitious energy efficiency portfolios or other programs that reduce sales.

LRAMs keep electric companies whole for short-term losses in base rate revenues that are due to their DSM programs (and potentially also distributed generation, since adjustments can be made on a timely basis). Recovery usually is achieved through a special rate rider. Unlike a decoupling mechanism (outlined in Section 3.1.4), an LRAM only corrects for load losses that are directly due to the administration of a specific energy efficiency or DSM program. They do not provide recovery for the revenue impact of other external forces, like weather or DSM programs managed by independent agents. Decoupling would address these other areas as well.

LRAMs require estimates of load savings from electric company DSM programs and such savings can be difficult and are sometimes controversial to calculate. As a result, the scope of DSM initiatives addressed by LRAMs is frequently limited to those for which load impacts are easier to measure.

---

[2] Act 129, Pennsylvania House Bill No. 2200, Session of 2008, *available at* http://www.puc.state.pa.us/electric/pdf/Act129/HB2200-Act129_Bill.pdf).

One example of an LRAM in practice comes from Arizona. The Lost Fixed Cost Recovery (LFCR) mechanism allows the electric company to recover a portion of unrecovered fixed costs resulting from energy efficiency and distributed generation programs. The LFCR is the result of the 2012 settlement of the Arizona Public Service (APS) rate review that was approved by the Arizona Corporation Commission. The LFCR allows APS to continue providing programs and services that help customers manage their monthly energy use, while also allowing APS to fund the operation and maintenance of the electric grid.

2.1.4 Revenue Decoupling

Traditional regulatory mechanisms keep customer rates constant between rate reviews, while actual electric company revenue floats up or down as a function of electricity sales. Revenue decoupling, however, allows automatic or semi-automatic revenue adjustments, which ensure recovery of the allowed revenue amount as electric rates are adjusted so that the allowed revenue is recovered.[3]

Revenue decoupling addresses the throughput incentive of higher electricity sales translating into higher electric company revenue by ensuring the electric company recovers its allowed revenue regardless of megawatt-hours and megawatts of electric company system use. Under this approach, the impact on electric company revenues between rate reviews from energy efficiency, demand response programs, and customer-sited distributed generation can be reduced or eliminated.[4]

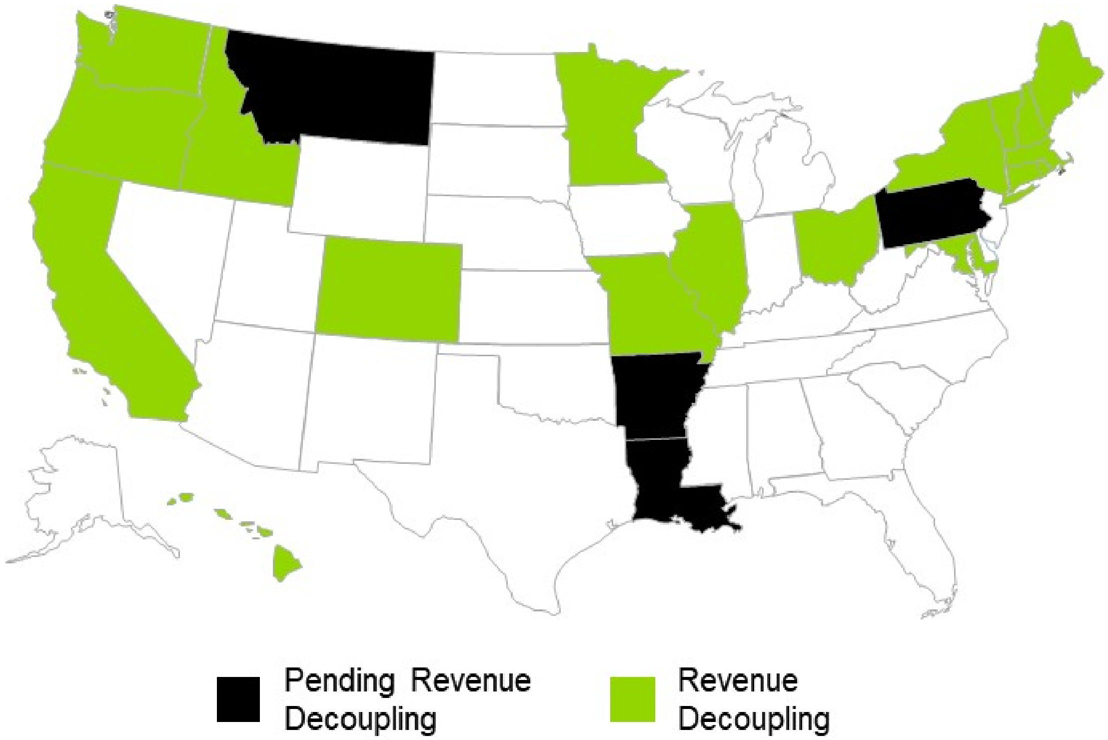
Notwithstanding the presence of a decoupling mechanism, a customer's bill is not decoupled from consumption. As a result, customers continue to be financially incentivized to reduce energy consumption while the electric company retains its ability to recover costs and revenue in a timely manner and avoid regulatory lag.

When well-designed, a decoupling mechanism implemented within a traditional ratemaking framework can reduce the frequency of rate reviews and the overall cost of the ratemaking process, which saves customers money. A decoupling mechanism can also serve as a critical component within a more comprehensive performance-based regulatory framework, including those that operate on an MRP cycle.

[3] Notwithstanding the presence of a decoupling mechanism, the target revenues determined in a rate review or multi-year rate plan is no guarantee that the utility will recover all of its costs, including a fair return.

[4] Lowry et al. PBR Technical Report at 2.

Figure 2-2. US Revenue Decoupling Prevalence by State: 2019



Source: Adapted from NRDC Gas and Electric Decoupling[5]

2.1.5 Multiyear Rate Plans

Under an MRP, electric company revenue requirements are set for multiple years in advance and electric company compensation is based on forecasted efficient expenditures rather than the historic cost of service. An MRP's two primary provisions promote cost containment incentives and reduce regulatory costs from rate reviews:[6]

- A rate review moratorium reduces the frequency of rate reviews, typically to once every 3-5 years.
- An attrition relief mechanism (ARM) escalates the revenue requirement or target revenues between rate plan periods to address cost pressures such as inflation and growth in number of customers independently of the electric company's own cost.

The combination of a rate review moratorium and the ARM approach to rate escalation can strengthen cost containment incentives and permit a well-run electric company to realize its target rate of return on equity (ROE) while materially reducing regulatory costs, which get passed along to customers. By loosening the link between an electric company's own cost and

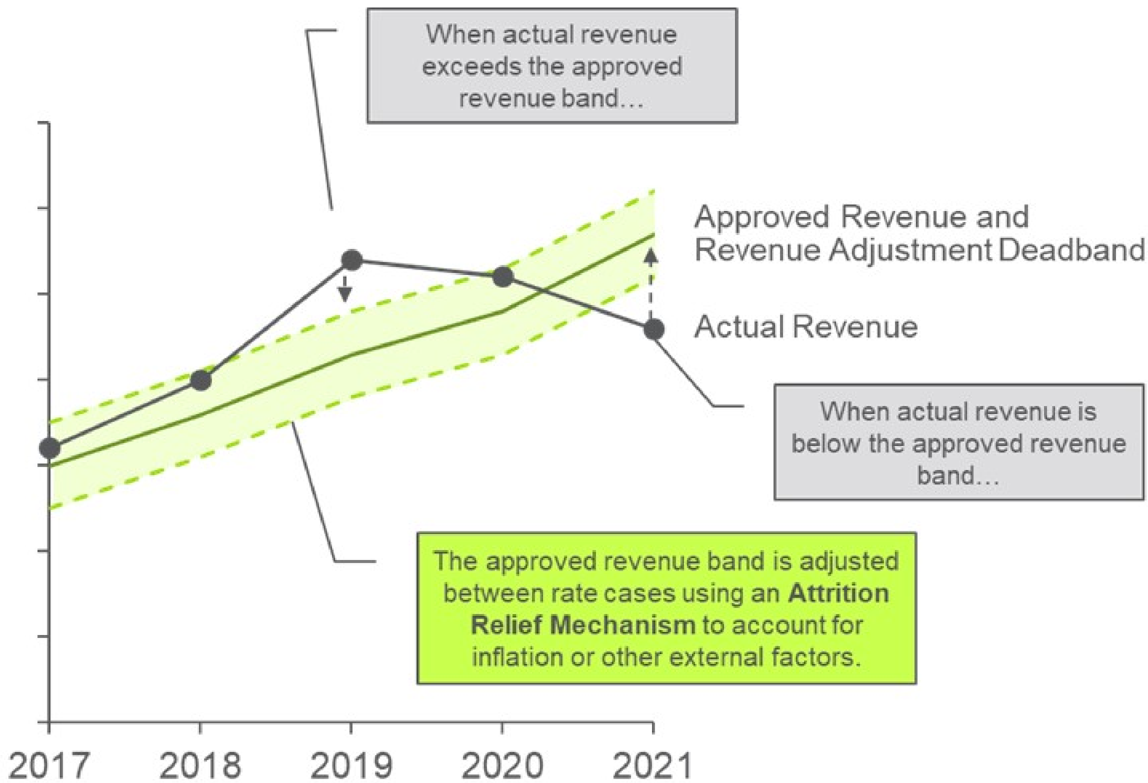
[5]Sullivan, Dylan and DeCostanzo, Donna, *Gas and Electric Decoupling*, NRDC. 24 Aug. 2018. https://www.nrdc.org/resources/gas-and-electric-decoupling

[6]M. Lowry, M. Makos, J. Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities* (July 2017), at iii (in-depth analysis of the multiyear rate plan approach to PBR for electric utilities for Lawrence Berkeley National Laboratory) ("Lowry MRP Report").

its revenue, an MRP can encourage electric companies to operate more efficiently by allowing the electric company to keep the additional profits from reduced operating costs.[7]

MRPs also free regulators, electric companies, and stakeholders from the demands of a capital-intensive annual or biannual rate review cycle. This decreased administrative burden results in savings for customers due to reduced regulatory expense, and also frees up regulators' resources to focus on more strategic initiatives to improve customer value over the long-term. Similarly, companies' resources can be redirected to its core business operations and to advancing innovation that increases customer value.

Figure 2-3. Multiyear Rate Plan with an Index-Based Revenue Cap and an Earnings Adjustment Mechanism



Source: Guidehouse

Figure 2-3. illustrates the high-level mechanics of an MRP. It reflects an MRP with an index-based revenue cap coupled with an ESM. Although MRPs can be structured in other ways (e.g., a forecasted ARM based on multiyear cost forecasts), more recently, jurisdictions appear to be coalescing around MRP designs with index-based ARMs.

In the US, MRPs were first used extensively in California, where a rate review plan was established in the 1980s that, with modifications, has limited the frequency of general rate reviews to this day. Iowa, Maine, Massachusetts, and New York were all early adopters.

---

[7] Lowry MRP Report at iii.

The use of MRPs in the US has spread to vertically integrated electric companies in other states including Colorado, Florida, Georgia, Virginia, and Washington.[8] In Hawaii, regulators have indicated a desire to move from a current 3-year MRP cycle to a 5-year MRP as part of a transition toward a comprehensive, modern performance-based regulation (PBR) framework. Regulators in Hawaii also would like to include a portfolio of performance mechanisms alongside other PBR elements, such as a symmetrical ESM. For Central Maine Power, an MRP afforded the company considerable flexibility in marketing to price-sensitive paper mill customers.

Outside the US, MRPs have largely displaced traditional COSR. In Canada, MRPs are becoming mandatory for natural gas and electric power distributors in Ontario, Quebec, British Columbia, and Alberta. Ontario, which regulates more than 70 power distributors, is now on its fourth generation of MRPs for these utilities. Overseas, the privatization of many energy electric companies in the last 25 years has forced governments to reconsider their approach to regulation. The majority have chosen MRPs over COSR. Electric companies in Australia, Britain, Germany, the Netherlands, and New Zealand are leaders in MRP development and implementation.[9]

2.1.6 Formula Rates

Formula rates are an alternative regulatory mechanism that adjusts an electric company's rates based on any changes to agreed-upon costs. This ensures that the electric company receives the authorized rate of return on investments that have been agreed to with the state regulatory commission. This tool provides a more automatic adjustment of rates based on costs than rate reviews, allowing electric company revenue requirements to more closely align with costs and avoiding the use of time and resources needed for a full rate review to make such adjustments, which saves customers money. Formula rate plans are typically reactionary and adjust rates based on variance between target ROE and actual ROE using actual incurred costs, but they can also be used to adjust rates based on projected costs. There are several approaches to calculating rate adjustments, such as using the difference between revenue and a pro forma cost of service calculated using a rate of return target.

The true-up mechanism often includes a dead band—a variance above or below the target ROE that is not large enough to trigger a rate adjustment. When an adjustment is triggered, the electric company’s actual, realized revenues are trued up to the authorized target revenues through a change to customer rates.

Formula rate plans protect the electric company from costs of risky investments if the investment is covered in the formula rate, but since rates are closely adjusted according to costs, formula rates weaken an electric company's incentive to control or minimize these costs. As a balance to this weakened incentive, formula rate plans are sometimes paired with other mechanisms such as targeted performance incentive mechanisms or a rate cap tied to an index such as inflation to ensure customers are adequately protected.

---

[8] Mark Newton Lowry, Tim Woolf, and Lisa Schwartz, *Performance-Based Regulation in a High-Distributed Energy Resources Future*, Future Elec. Util. Reg. No. 3 (2016) (“Lowry & Woolf Technical Report”), at 29.

[9] Lowry & Woolf Technical Report at 30.

Illinois legislators passed the Energy Infrastructure Modernization Act, allowing for a formula rate model, which motivated Illinois utilities to pursue grid modernization and reduced the resources dedicated to formal rate cases.

Problem statement: Utilities needed a clear path to cost recovery for grid modernization investments.

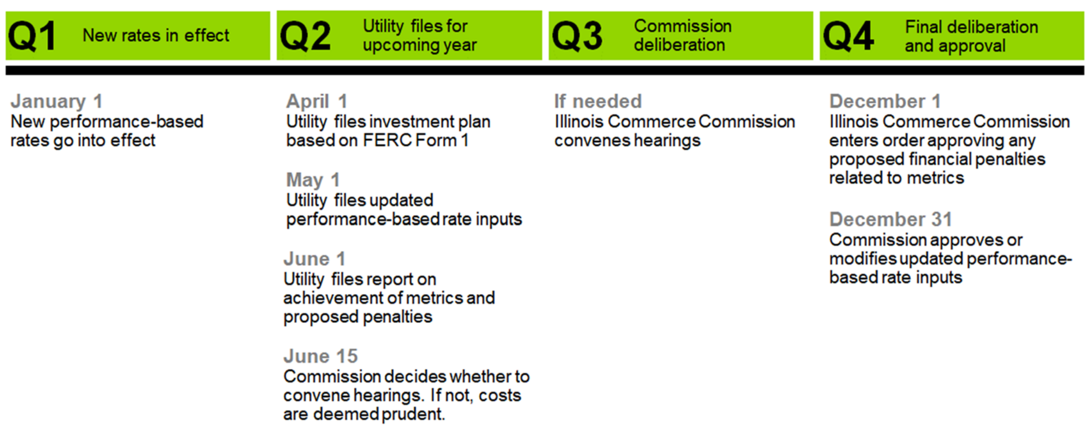
Solution: In 2011, Illinois passed legislation for a formula rate model for Illinois utilities. The formula rate was paired with a multiyear capital plan that was reviewed by regulators prior to recovery in formula rates. The model intended to motivate utility investment in grid modernization using an annual resetting of revenue to reduce risk in these investments without formal rate case and complex regulatory filings.

Outcome: Successful grid modernization investment and deployment with measurable results of grid performance, reduced regulatory lag, and reduced administrative and regulatory costs.

Key Takeaways: Formula rates ensure that the utility receives the authorized rate of return on agreed-upon investments. This tool provides a quicker, more frequent adjustment of rates based on costs than rate cases, thereby allowing utility revenue requirements to more closely align with costs and avoiding the use of time and resources needed for a full rate case to make such adjustments.

Figure 2-4 outlines the regulatory process followed by Commonwealth Edison as it operates under Illinois' formula rate plan.

Figure 2-4. Illinois Performance-Based Formula Rate Regulatory Cycle



Source: Adapted from Presentation by Anil Dhawan

2.1.7 Earnings Sharing Mechanism

An ESM serves to share amounts of electric company earnings with customers that fall outside a range determined by regulators. ESMs are established to ensure that the electric company's earned profits are neither excessive nor insufficient by sharing this excess or insufficiency with the customer. An ESM can provide some assurance that company earnings will not excessively benefit or suffer from exogenous factors not under electric company control or from unintended results of alternative regulatory mechanisms. To the extent that realized earnings (in terms of percent ROE) or actual earnings (in terms of EBITDA) exceed certain approved levels, increasing proportions of the realized earnings are returned (shared) with customers as a credit toward future revenue collection.

Some jurisdictions are exploring the concept of a symmetrical ESM collar, providing both upside and downside sharing of earnings that fall outside of a regulator-approved range.[10] An ESM's design should consider the overall framework of regulatory provisions, including the full portfolio of alternative mechanisms in effect.

In Hawaii, the current regulatory framework for the Hawaiian Electric Companies includes an ESM to ensure that automatic attrition relief adjustments over the course of their 3-year MRPs do not result in excessive electric company earnings. The mechanism calculates and compares the achieved percentage return on common equity from the most recent full year recorded results with the ROE allowed in the most recent general rate review. If the realized regulatory return on common equity is in excess of the allowed return, specified proportions of the excess is returned to customers.

- First 100 basis points excess => 25% of excess is returned to customers
- Next 200 basis points excess => 50% of excess is returned to customers
- Above 300 basis points excess => 90% is returned to customers

In the context of the Hawaii Public Utility Commission's investigation into PBR, regulators are expected to allow for both upside and downside sharing of earnings between the electric company and customers when earnings fall outside a Commission-approved non-adjustment range or "dead band." The quantification of earnings subject to adjustment by the updated ESM in Hawaii will be comprehensive, including contributions from target revenues, performance incentive revenues, cost trackers, and other components of overall electric company revenues.[11]

2.2 Performance Mechanisms

Performance mechanisms are a way for regulators to align customer, electric company, and policy goals by providing incentives for the electric company to reach performance targets through the public display of metrics or benchmarking, or more overtly through financial reward for achieving certain levels of performance.

Metrics can be used in several ways to help track progress and reward exemplary electric company performance. These can be broken down according to three primary applications of expanding scope: 1) reported metrics, 2) scorecard, and 3) performance incentive mechanisms (PIM), as Figure 2-5. illustrates.

[10] *See, e.In re Public Utilities Commission*, *Instituting a Proceeding to Investigate Performance-Based Regulation*, Docket No. 2018-0088, Decision and Order No. 36326, filed May 23, 2019 ("Hawaii Decision and Order No. 36326").

[11] Hawaii Decision and Order No. 36326, at 9.

Figure 2-5. Applications of Metrics

Source: Guidehouse

Reported metrics can enhance transparency as a regulatory tool to incentivize specific electric company performance through tracking and reporting results. A scorecard compares a reported metric to a performance target, benchmark, or peer. A collection of scorecards that highlight electric company performance can be displayed in a public facing; centralized hub known as a dashboard. A PIM is a metric paired with a performance target and a financial incentive. PIMs can help financially incent electric company achievement toward core public policy goals.

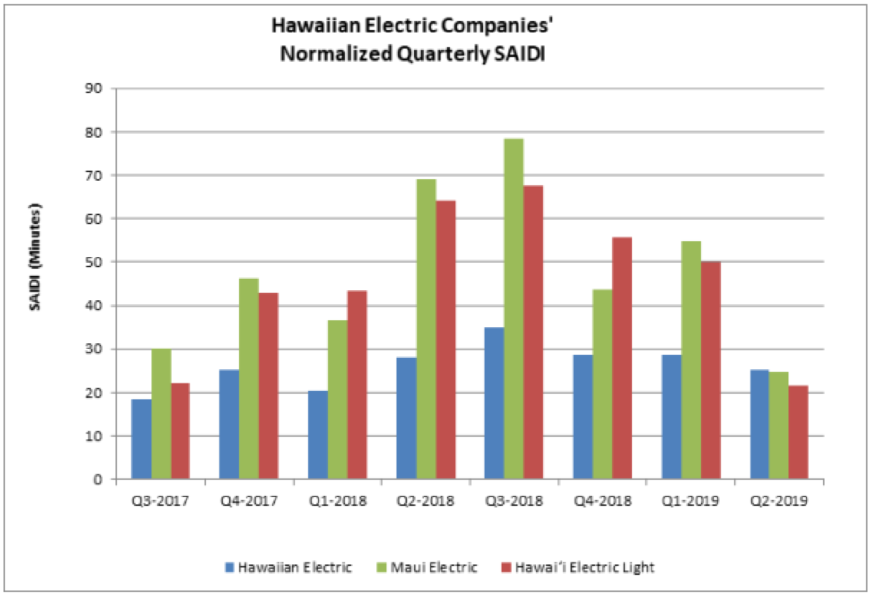
Performance mechanisms can be used to assess diverse areas of the electric company's performance, such as safety and reliability, customer satisfaction, and adoption of energy efficiency programs. The reported metrics and scorecards can also be used as building blocks for an electric company, helping it to build metric tracking capabilities and gather historic and peer-compared performance trends to ultimately pursue a PIM.

2.2.1 Reported Metrics (Level 1)

Reported metrics are often used to increase transparency, most often related to safety and reliability requirements of an electric company. Reporting standalone metrics can be useful to track achievement of prioritized outcomes and can inform ongoing market evaluation and policy assessments. Further, reported metrics can serve as the foundation for developing scorecards or PIMs—the other applications detailed below. Reported metrics may also help to inform the development of revenue adjustment mechanisms as well as track the efficacy of all regulatory mechanisms over time.

In Hawaii, regulators have directed the Hawaiian Electric Companies to display key performance metrics prominently on their website. Reported metrics include service reliability, such as SAIDI and SAIFI, along with metrics tracking financial performance and customer service.

Figure 2-6. Illustrative Example of Reported Metrics



Source: Hawaiian Electric Companies

2.2.2 Scorecards (Level 2)

When a metric is paired with performance targets, benchmarks, or peer comparisons it becomes a scorecard. Typically, a scorecard makes use of visuals so people can easily understand performance and how it compares to targets, other electric companies, or other regions. Like a reported metric, a public-facing scorecard reports electric company performance information in a central location and presents the data in a meaningfully contextualized and transparent manner. Scorecards allow regulators and other stakeholders to quickly review and digest electric company performance across a number of outcomes and metrics. A scorecard should be readily accessible and featured prominently on the electric company's or commission's website. The information provided in scorecards should be clear, concise, comprehensive, and up to date.

> **"The three levels of performance mechanisms form a progression toward greater utility accountability and financial reward for exemplary results.**

By adding a target or appropriate benchmark to a reported metric, scorecards can encourage better achievement of regulatory outcomes than through reported metrics alone. For innovative focus areas where the data to be measured are uncertain, or when the outcome is not fully controlled by the electric company, scorecards (composed of a metric plus a performance target) can be used as a no-regrets test bed before attaching a financial incentive on the path to developing a metric into a PIM.

The Ontario Energy Board maintains an electric company performance dashboard where it houses a collection of scorecards across a variety of categories, including customer focus, operational effectiveness, public policy responsiveness, and financial performance. Customers and regulators are able to use the dashboard to see how an individual electric company's performance measures up to preestablished targets and to compare the performance of two or more companies against one another. In this vein, the use of metrics provides a view of how an electric company creates value for customers.

Figure 2-7. Illustrative Example of Scorecards Shown in a Dashboard

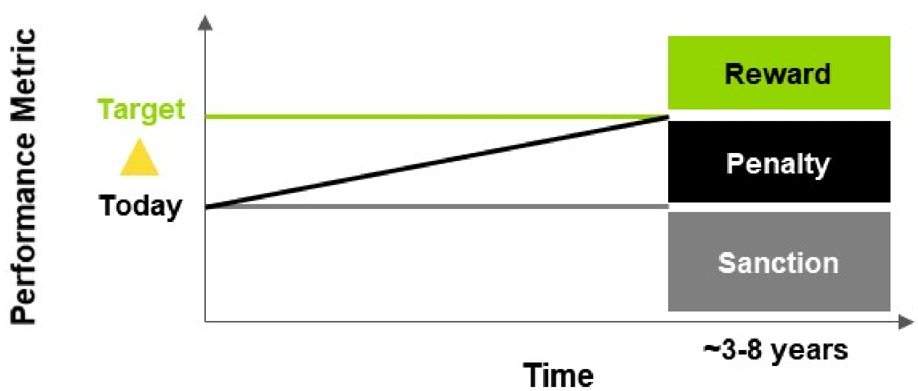
Public Policy Responsiveness			
Utility	**Net cumulative Energy savings (percent of target achieved)**	**Renewable generation connection impact assessments completed on time**	**New micro-embedded generation facilities connected on time (target: 90%)**
Utility A	62.1%	100%	98.34%
Utility B	44.22%	100%	100%

Source: Guidehouse; adapted from Ontario Energy Board, Electricity Utility Performance Dashboard

2.2.3 Performance Incentive Mechanisms (Level 3)

A PIM is a metric paired with a performance target and a financial incentive that forms a complete performance-based ratemaking approach. PIMs provide financial motivation for electric companies to improve performance toward established outcomes increasing value for customers, or to discourage underperformance. Using a financial award or penalty, a PIM can promote achievement of a prioritized outcome more strongly than a scorecard or reported metric. Examples of existing PIMs in Hawaii include service quality PIMs (SAIDI, SAIFI, and Call Center Performance) and policy PIMs related to the timely acquisition of cost-effective demand response resources from third-party aggregators and the successful procurement of grid-scale renewable energy. Targets established for PIMs may be tied to state energy goals or other established regulatory priorities and should balance the costs of achieving the target with the potential benefits to ratepayers.

Figure 2-8. Symmetrical Performance Incentive Mechanism



Source: Guidehouse

Figure 2-8. illustrates the mechanics of a symmetrical PIM that provides for a financial award or a financial penalty depending upon whether the electric company outperforms or underperforms against prespecified performance targets.

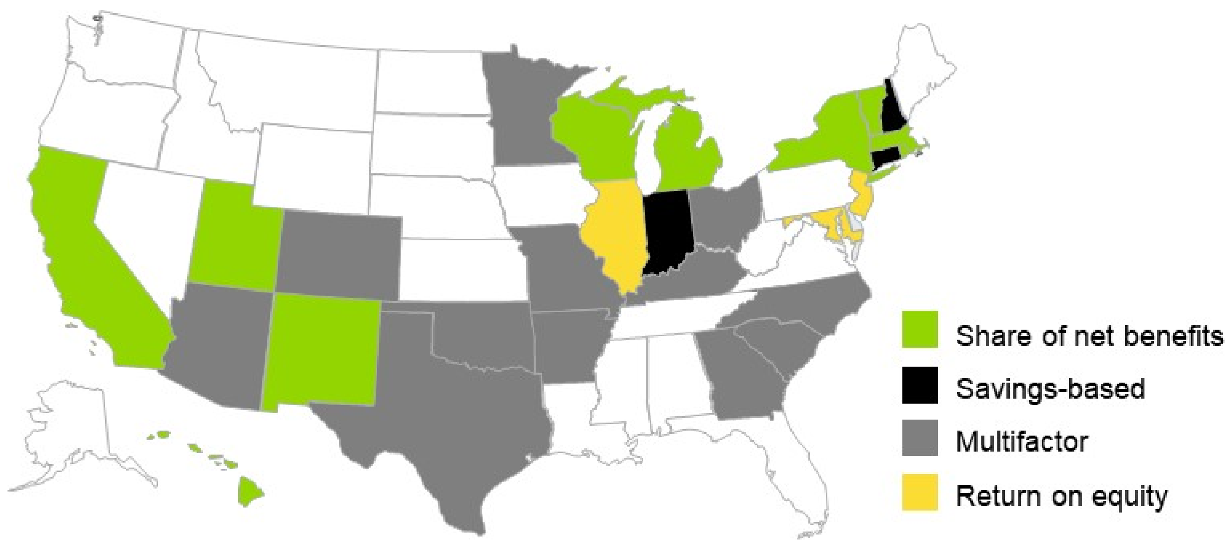
PIM design and the application of metrics to other regulatory mechanisms require significant attention to many details, such as size of financial incentives and use of dead bands. Among electric companies, the most common application of PIMs to date is to encourage energy efficiency performance. The wide adoption of financial incentives for energy efficiency has coincided with a dramatic increase in performance achieved by companies.

These incentives are typically designed in one of four formats:

- **Share of net benefits:** Electric companies earn a percentage of the savings from their efficiency programs
- **Savings-based incentive:** Electric companies earn a reward for meeting a preestablished goal
- **Multifactor incentive:** Electric companies earn a reward for meeting a set of multiple preestablished savings-based goals
- **ROE:** Electric companies can include energy efficiency program spending in rates

Figure 2-9. summarizes the adoption of these four approaches to energy efficiency performance incentives across the US.

Figure 2-9. Performance Incentive Mechanisms by State: 2019



Source: American Council for an Energy-Efficient Economy

While PIMs have been established across several jurisdictions, their development is expected to continue as the costs of new technologies like energy storage decline so that electric companies have incentives to consider those resources and reduce overall ratepayer costs. Load factor (the ratio of average load to peak energy use) is one potential PIM that could be effective in deploying energy storage and other DER. Storage is uniquely qualified to improve load factor as it distributes peak loads and can make the most significant improvement to load factor per unit of any technology. Since load factor is based on annual peak, storage can also contribute to meeting other potential PIMs (i.e., peak demand reduction) at the same time. In both vertically integrated and deregulated markets, well-crafted PIMs can be effective to foster the adoption of energy storage and DER.

2.2.4 Considerations for Metric Design

To be most effective, metrics must be carefully designed with several principles in mind.

Metrics should:

1. Reflect desired outcomes
2. Be clearly defined
3. Be quantifiable through reasonably available data
4. Be easily interpreted
5. Be easily verified

Importantly, the degree of electric company control over a particular outcome should be considered. Although metrics should reflect the impact of factors that are largely within the electric company's control, there may be circumstances where exploring a metric that captures some percentage of elements outside of the electric company's control is warranted. Reported metrics are important for tracking progress against prioritized outcomes, some of which are influenced by factors that are not directly controlled by electric companies (for example, capital formation and even, in some respects, growth in DER assets). Nonetheless, these metrics should be measured and reported to support ongoing market evaluation.

The degree of electric company control over outcomes is a more significant consideration for those metrics that are used in scorecards and, especially, for PIMs. For these applications, metric and mechanism design must appropriately reflect factors that the electric company can influence. Even in these cases, it might not be appropriate to strictly apply a principle of electric company control, as it can be helpful to align and make the electric company more responsive to external market factors such as fuel costs.

Hawaii Public Utilities Commission staff have suggested prospective metrics be considered as a basis for reported metrics, scorecards, and/or PIMs.[12]

New York Renewing the Energy Vision (REV) Financial Mechanisms

The New York State Public Service Commission (PSC) issued an order in 2016 to adopt a new regulatory model that incentivizes utilities to act according to REV objectives (system reliability, customer knowledge and capabilities, reduced carbon emissions, etc.) by better aligning utility shareholders' financial interests with customers' interests. This is done by adding a combination of market-based and outcome-based PIMs for utilities, which the PSC calls Earning Adjustment Mechanisms (EAMs).

Each utility proposes the performance areas, metrics and targets, and the level of incentive it would earn individually with the PSC. Targeted areas include system efficiency and peak reduction, energy efficiency, the distributed generation interconnection process, customer engagement in innovative programs, and GHG reduction through increased renewable sources and electrification of transportation and building heating and cooling.

[12] *In re Public Utilities Commission*, Docket No. 2018-0088, "Staff Proposal for Updated Performance-Based Regulations," filed February 7, 2019, at 35-37.

2.3 Other Regulatory Mechanisms

In addition to revenue adjustment mechanisms and performance mechanisms, regulators have additional policy tools at their disposal. This section highlights other regulatory mechanisms that can help modernize the current regulatory framework.

2.3.1 Shared Savings Mechanisms

Under a shared savings mechanism, an electric company that can reduce expenditures from a baseline or projection will be allowed to retain a portion of savings as profit while returning the remainder to customers, often in the form of lower rates.[13] Allowing the electric company to retain some level of savings provides an incentive for electric companies to seek more cost-effective solutions without compromising customer and shareholder interests. Customers also directly benefit, as savings can translate to reduced rates.

Shared saving mechanisms can apply to all expenditures (i.e., a TOTEX approach), CAPEX or OPEX only, or some subset of expenditures such as non-wires solutions or demand management programs. A comprehensive shared savings mechanism for reduced spending on the electric company's entire portfolio of CAPEX and OPEX does not exist today in the US; however, shared savings mechanisms are often the basis for targeted programs such as energy efficiency. According to ACEEE, 13 states use this approach to incent electric company energy efficiency performance.[14]

The design of shared savings mechanisms depends on the type of expenditures covered and how much risk is associated with investment. Regardless of the specifics, however, all shared savings mechanisms should have a transparent methodology to develop baselines and projections to mitigate the risk of inflating costs of alternatives against which savings are measured. There should also be a clear process for evaluating savings to prevent ex post debates over savings measurements. Another important consideration is whether shared savings incentives should be symmetrical, such that risks of cost overruns are also borne by electric company shareholders.

Earnings on Non-Wires Solutions

Shared savings approaches are also being pioneered for non-wires alternatives or non-wires solutions (NWS). NWS projects allow electric companies to defer or avoid conventional infrastructure investments by procuring DER that can lower costs and emissions while maintaining or improving system reliability. Both New York and Rhode Island have programs set up to share the savings resulting from NWS projects.

In 2017, the New York Public Service Commission adopted an incentive for Con Edison to pursue cost-effective NWS to traditional infrastructure projects. The incentive is a function of net benefits of the NWS, which includes not only cost savings but also societal benefits such as greenhouse gas reduction. Con Edison receives 30% of net benefits, with the other 70% going to customers. Additionally, Con Edison shares the risk of cost savings and overruns 50/50. The

---

[13] Dan Aas and Michael O'Boyle, *You Get What You Pay For: Moving Toward Value in Utility Compensation, Part 2–Regulatory Alternatives*, Energy Innovation/America's Power Plan, 2016, available at https://americaspowerplan.com/wp-content/uploads/2016/08/2016_Aas-OBoyle_Reg-Alternatives.pdf.

[14] Seth Nowak, et al., *Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency*, American Council for an Energy-Efficient Economy (ACEEE), 2015, ***available at*** http://aceee.org/sites/default/files/publications/researchreports/u1504.pdf.

shared savings incentive is capped at 50% of total net benefits and can be wiped out completely by cost overruns.

In Rhode Island, National Grid proposed a System Reliability Procurement incentive mechanism consisting of action-based and savings-based incentives. The savings-based incentives split the net benefits associated with NWS projects, with 80% going to customers and 20% going to National Grid.

2.3.2 CAPEX and OPEX: Treating Expenditures Equitably

Traditional electric company regulation creates an inherent bias for electric companies to prefer electric company-owned capital investments over other solutions because electric companies earn a rate of return on CAPEX but not OPEX. This disparate treatment of CAPEX and OPEX is increasingly problematic as traditional CAPEX solutions are not always the best or most cost-effective way to bring value to customers. Emergent solutions, such as cloud computing and virtual power plants, underscore the need for a framework that financially rewards an electric company for pursuing not just the least-cost but the highest value solution for customers, irrespective of whether that solution would be classified as CAPEX or OPEX.

2.3.2.1 Return on Service-Based Solutions

Earning a rate of return on service-based solutions allows electric companies to earn a return on payments for service-based solutions, such as cloud computing services or DER, similar to returns on a capital investment even though they do not own the solution. For example, a DER incentive adder allows electric companies to earn a return on the total cost of electric company payments to a third party for a DER-derived service solution.[15] With an adder, the rate of return may or may not be commensurate with the rate of return for CAPEX but is intended to provide some return on expenses that would traditionally be recovered as expenses without associated earnings. If these expenses are made more equivalent to CAPEX by providing earnings at a rate intended to approximate the return on capital investment, this approach could also be referred to as rate-basing service-based solutions.

> "One might ask: why provide the IOUs with any incentive at all? Why not just direct the utilities to choose DERs whenever they are less costly than traditional distribution investments? The problem is that, given the complexity of the distribution system, this Commission is ill-equipped, at least at present, to determine with the necessary specificity exactly when and where such DER deployment opportunities may exist… Practically speaking, command-and-control regulation faces major challenges in this context. Instead, if our objectives are to be achieved, we should create the appropriate utility incentives, such that the IOUs will affirmatively seek opportunities to deploy DERs in the pursuit of their own shareholders' interests."
>
> **-Former California PUC Commissioner Mike Florio on mandates versus incentives**

Cloud Computing and Pay-As-You-Go Services

The IT transition from on-premise hardware and software to cloud-based computing is underway in the electric company sector as energy providers seek out increased customer benefit. PUCs have recognized cloud and software as a service (SaaS) solutions' ability to provide scalable, mobile, and resilient technology to electric companies and their

[15] Advanced Energy Economy Institute, *Utility Earnings in a Service-Based World: Optimizing Incentives for Capital- and Service-Based Solutions*, 2018. ("AEE, Utility Earnings in a Service-Based World")

customers. Despite the many benefits of cloud computing and SaaS, these technologies are at a disadvantage when compared to on-premise IT investments. This is because, under traditional accounting and ratemaking rules, on-premise IT is treated as a capital asset that may earn a rate of return, while cloud computing and SaaS solutions are treated as OPEX, with no ability to earn a return. To fully take advantage of the benefits of cloud-based software, these technologies must be able to compete on more equal regulatory footing.

In recognition of these challenges, the Illinois Commerce Commission has proposed allowing electric companies to use a regulatory accounting alternative that provides more equitable financial treatment of cloud-based solutions. The proposed rule allows for electric companies to pre-pay for a cloud service and amortize those costs and derive earnings from them as it would a traditional, on premises asset. The proposed rule goes further, however, and would permit some earnings on pay-as-you-go service, though not on an equal level with prepaid cloud computing services. This is an important distinction, as the electric company can leverage the flexibility and scalability of cloud computing with a pay-as-you-go model (in which the electric company can pay periodically based on its actual usage of a service rather than pay up front and lock itself into a predefined quantity of service). This affords the electric company greater operational flexibility, decreasing risk stemming from sunk investment in owned IT, while providing customers with potential cost savings if it uses less of a service than anticipated.

DER Adder Incentive

In California, the Competitive Solicitation Framework Pilot allowed an incentive equal to 4% for annual DER payments that displace or defer CAPEX on traditional distribution project investments.[16] There are differing perspectives on what the right size of a DER incentive should be and also on whether the regulatory context is the appropriate place to provide such financial incentives (as opposed to government-provided subsidies or credits). Regardless of the source, the size of the incentive needs to be large enough to ensure non-capital solutions receive sufficient consideration. In addition, allowing a rate of return on certain projects and solutions requires regulatory oversight to determine which are appropriate for such an incentive and which are not. Mechanisms should also address any unintended incentives to increase expenditures for service costs to increase any resulting incentives.

2.3.2.2 Capitalization of a Prepaid Contract

Another option is the capitalization of a prepaid contract, which treats an expense (such as payments for a service) like a capital investment by placing it into the rate base, amortizing it, and recovering costs over time. For example, a service payment would be prepaid for a number of years and would be amortized over the length of the contract. The electric company would collect its annual carrying costs, including repayment for the electric company expenditure and return on unamortized balances. With this option, the electric company earns a rate of return on the prepaid contract in a similar manner and at a similar level as traditional rate-based assets. This approach may be easier than more innovative approaches, such as TOTEX accounting,[17] since it uses an existing regulatory approach for which there are well-established accounting standards.

---

[16] California Public Utilities Commission, "Integrated Distributed Energy Resources," a*vailable at* http://www.cpuc.ca.gov/General.aspx?id=10710.

[17] "Totex" accounting is an approach where a utility's capital expenditures and operating expenses are combined into a single regulatory asset. To date, no utility in the US has implemented this approach, in part, due to concerns over accounting standards.

While this approach mitigates the electric company's bias toward capital solutions, the electric company may need additional incentives to choose the most efficient approach, especially if the CAPEX option provides an opportunity to place a larger asset in the rate base. The contract length is another factor that will influence electric company decision-making; longer-lived contracts will allow the electric company the opportunity to earn more for the same level of initial investment. Not all service-based solutions may be treatable as prepaid contracts, limiting the applicability of this solution.

The New York Public Service Commission (NY PSC) issued a declaratory statement in its Reforming the Energy Vision (REV) Track 2 order that electric companies could capitalize prepaid SaaS contracts.[18] The method that the NY PSC took, prepaying the total cost of service contract and recording it as a regulatory asset in the rate base, is a simple solution that resolves the disincentive for electric companies to use cloud computing or third-party solutions and places these services on equal footing with on-premise, traditional solutions, allowing the electric company to select a solution that provides the most value to the system and to customers.

Using the New York approach, regulators can incentivize electric companies to cost-effectively procure NWS or DER solutions instead of traditional electric company-owned assets, unlocking savings for all customers where available. An electric company could enter into a power purchase agreement (PPA) with a third-party DER aggregator (e.g., rooftop PV or distributed energy storage) and earn a return on that procurement. By prepaying for a 10-year PPA, an electric company could capitalize the expense and earn a return that is equivalent to what the electric company would have earned on a CAPEX.

3.0 Performance-Based Regulation

PBR is an approach to regulation that combines a set of alternative regulatory mechanisms and processes with an aim to better align the desired outcomes that matter to customers, companies, and regulators. PBR should not necessarily be viewed as a next step in applying the mechanisms discussed in Section 3. Rather, PBR is a way for regulators to reform legacy regulatory structures to enable innovations within modern power systems.

> **"A PBR framework can provide incentives for the utility to manage costs without compromising service or reliability, while calibrating financial incentives with public interest.**

Within a performance-based regulatory framework, an electric company is financially incentivized based on its achievement of specific performance targets, providing an opportunity to earn a higher return if the company can deliver on the identified objectives. PBR also can be a flexible regulatory environment that affords creativity and adaptability, leaving room for innovation of technology and offerings for customers. This approach contrasts with traditional ratemaking where electric company rates are based primarily on incurred costs and rate setting is often contested, which may motivate electric companies to invest in fixed assts or have less time and resource for innovation and may not provide adequate rewards for cost containment and productivity improvements.

---

[18] New York Public Service Commission, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, Docket No. 14-M0101, May 9, 2016, at 104.

PBR is not a singular option but should be viewed as a system or set of tools that may be adopted individually or in combination to achieve specific objectives. PBR is made up of several elements that can be applied in different ways and in different combinations, intended to better align electric company return with today's operating environment. Some of these mechanisms are applied as standalone elements in regulatory frameworks that are largely traditional.

PBR Generally Includes Three Critical Components:

1. Revenue decoupling mechanism
2. MRP
3. Performance mechanisms (including PIMs)

3.1 Creating Flexibility for Innovation and Strong Alignment with Customer Interests

The desire to better align electric company service provision and electric company revenues with delivery of customer and societal value is motivating the consideration of performance-based incentive structures is. As customer adoption of DER continues apace and as emerging technologies enable new grid solutions more broadly, a contemporary PBR framework can provide earnings opportunities that enable electric companies to thrive in a changing environment, while meeting customer-oriented objectives and delivering value-added services.

Well-designed PBR may help address some of the challenges inherent in the traditional regulatory model by creating a structure that rewards exemplary electric company performance irrespective of the nature of the investments made to achieve it (e.g., investment in a capital project versus investment in efficiency measures). By providing incentives for specific outcomes and objectives, a PBR framework can provide an electric company with the opportunity to earn fair compensation based on a business model that is well-aligned with customers' expectations.

GREAT BRITAIN'S RIIO.
RIIO is one of the best-known examples of PBR in practice. RIIO stands for "Revenue = Incentives + Innovation + Outputs" and is composed of a number of alternative regulatory mechanisms, including MRPs (eight-year "price control" periods), benchmarking, ESMs, and PIMs. The administration of these is interlaced and subject to significant regulatory review and negotiation between the regulator (Ofgem) and the regulated companies.

NEW YORK'S REV.
REV aims to establish utilities as Distribution System Platforms across which retail energy service providers and DER compete to meet customer needs, ensure system reliability and resiliency, and reduce emissions. A suite of PIMs, described as Earnings Adjustment Mechanisms ("EAMs") in New York, serve to link specific outcomes (e.g., system efficiency, customer engagement) with utility financial interests. The utility also stands to benefit from new forms of revenues associated with operation and facilitation of distribution-level services (i.e., Platform Service Revenues). Metrics of interest to the utility and regulators, but which have no financial stake, are also being implemented (i.e., Scorecard Metrics) for transparency purposes, benchmarking opportunities, and/or to lead toward eventual inclusion in an EAM.

Overarching objectives that may be addressed by PBR include:

- Incenting cost reduction
- Incenting achievement of state and regulatory policy goals
- Improving performance in areas that have previously been unsatisfactory
- Integrating technological advances, such as advanced metering and demand response capabilities
- Encouraging and facilitating innovation in how the grid is operated and how customers are served
- Encouraging a low cost, customer-centric future

A PBR framework can open opportunities for electric companies to earn new revenues from the provision of value-added services. Examples of value-added service revenues related to DER transactions could include, but are not limited to, fee-based transactions, lead origination for third parties, subscription or access fees, and value-added data analysis. Other value-added services related to DER utilization could also be considered, including the installation or optimization of microgrids.

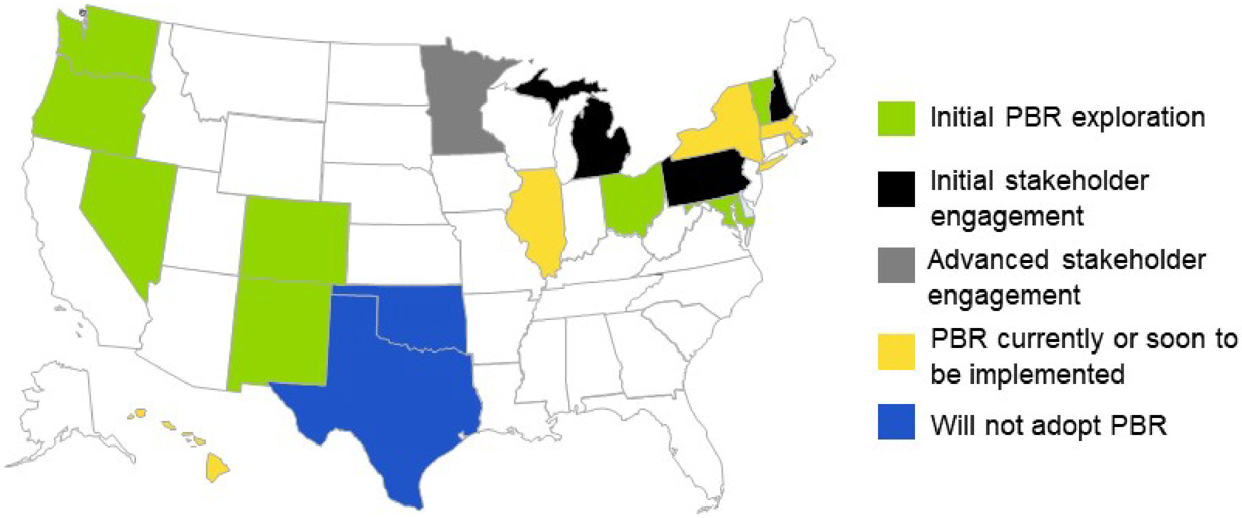
One near-term opportunity for new service revenues may be the sharing of customer and system data. Sharing of data must not compromise Personally Identifiable Information. Rather, genericized customer data can be analyzed to help identify operational efficiencies, design new and more efficient rates, and develop new products and services. Given that the electric company has control and access to most of the pertinent data on the power system, finding equitable opportunities to incent new product creation and services may benefit all stakeholders. Unleashing system data to enable better understanding of customer and system needs, while maintaining important cybersecurity considerations, will continue to advance DER toward integration into system operations and power system planning.

As policymakers increasingly embrace this transformation and see it succeed in their jurisdictions, they can enable their electric companies to further focus on delivering customer value. Capital investment, whether in substations or IT systems, could be structured to meet defined performance outcomes. Multiyear business and capital investment plans could replace annual rate reviews, yielding less time in the hearing room and more time enhancing the system and serving customers.

3.2 Guiding Principles to Inform Performance-Based Regulatory Frameworks

About one-third of states have explored performance-based regulation, with a few that have adopted the framework, a few that have rejected it, and most still assessing the opportunities regarding PBR. Figure 3-1. provides an overview of the status of each state in exploring or adopting PBR. Adoption of modern PBR is nascent, and those states that are implementing the framework have taken varying approaches with varying degrees of revenue decoupling and performance incentives.

Figure 3-1. State Exploration and Adoption of Performance-Based Regulation



Source: Adapted from Enerknol-Wood Mackenzie Report

When contemplating a PBR approach, core principles that are calibrated with key policy goals and objectives must be considered. The following guiding principles are offered to help inform policymakers as they explore development of a PBR framework.

Customer-Centric Approach

A modern, performance-based regulatory framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of electric company system functions.

The details of a PBR framework will influence the allocation of realized cost savings and other benefits between electric companies and their customers. There are various mechanisms by which such savings could be ensured in a comprehensive PBR framework, including through one or more benefit sharing provisions under an MRP.

In the era of DER, there is a proliferation of new technologies and solutions for customers emerging in the marketplace. Electric companies can serve their investors' and customers' interest by exploring innovative solutions with third parties. PBR can support this environment by blending process efficiency, freeing up the time and resources to innovate with incentives designed to be met in part as a result of innovative partnerships.[19]

Administrative Efficiency

Most existing traditional regulatory frameworks are complex, and the cadence and frequency of traditional rate reviews are often resource intensive for companies, ratepayer advocates, and regulators alike. PBR offers an opportunity to simplify the regulatory framework, save money for customers, and enhance overall administrative efficiency—allowing regulators to focus on longer-term strategic policy goals and allowing electric companies to focus on delivering enhanced customer value.

[19] Utility partnership with the market are proliferating. A number of utilities are investors in Energy Impact Partners (EIP) a collaborative innovation model and, in New York, NYSERDA has launched REV Connect - a platform to match utility interests with third party innovative ideas and technologies.

Electric Company Financial Integrity

From the inception of utility regulation, a fundamental goal has been to ensure the electric company's financial health. The financial integrity of an electric company is essential to its basic obligation to provide safe and reliable electric service at an affordable rate for its customers. The electric company is a critical community partner and serves an integral role in achieving the state's energy policy goals. In some locations, a well-designed PBR framework could help to reduce regulatory lag and preserve the electric company's opportunity to earn a fair return on its business and investments, while maintaining attractive electric company features, such as access to low cost capital.

3.3 Potential Elements of a PBR Framework

Table 3-1 summarizes certain alternative regulatory mechanisms that, particularly when used together, can help create space for innovation, enhance customer satisfaction, lower overall costs, and facilitate the development of value-added services.

Table 3-1. Potential Elements of a PBR Framework

Revenue Adjustment Mechanisms	
Multiyear Rate Plan (MRP) and Indexed Revenue Cap	**3-5-Year Control Period** with **Externally Indexed Revenue Cap** allowing interim adjustments to both CAPEX and OPEX pursuant to a revenue cap to an externally indexed formula (e.g., inflation less productivity). A 3-5-year plan period will help to incentivize cost containment over the duration and will free up resources previously spent on annual rate reviews to focus on grid modernization and adding customer value.
Revenue Decoupling	A **revenue decoupling** mechanism to true-up revenues to an annual revenue target, which ensures the electric company receives the target revenue, regardless of increases or decreases in energy sales. Revenue decoupling smooths out volatility that otherwise would occur over a 5-year MRP period and removes an incentive barrier to energy efficiency and DER adoption.
Earnings Sharing Mechanism (ESM)	A symmetrical **ESM** that provides both upside and downside sharing of earnings between the electric company and customers when earnings fall outside a Commission-approved range. A symmetrical ESM can act as a "safety valve" around earnings, allowing for a meaningful percentage of overall earnings to be tied to performance-based incentives while protecting the electric company's financial integrity and the customers' interests.
Performance Mechanisms	
Performance Incentive Mechanisms (PIMs)	A set of **PIMs** designed to help drive achievement of regulatory and policy outcomes such as reliability, customer engagement, and DER asset integration.
Scorecards	**Scorecards** with targeted performance levels to track progress against emergent regulatory outcomes, such as: customer engagement, cost control, and GHG reduction.
Reported Metrics	A portfolio of **reported metrics** to highlight activities under the following regulatory outcomes such as affordability, customer equity, interconnections, electrification of transportation, and resilience.

Other Regulatory Mechanisms	
CAPEX/OPEX Parity	**Shared savings mechanisms** to incentivize the cost-effective pursuit of NWS and revise regulatory ratemaking treatment so electric companies can **earn a rate of return on third-party service solutions**.
Innovation	A **regulatory sandbox** to create space for the development of innovative products and services and experiment with **subscription pricing** to facilitate enhanced customer access to new products and services.
Value-added Services	Examine how **value-added services** can be incorporated into the regulatory framework to diversify electric company revenues in the near-term and facilitate a customer-centric model in the longer term.

4.0 Regulatory Processes and Approaches Focused on Innovation

Regulators, companies, and stakeholders are increasingly recognizing that the often restrictive and sometimes adversarial nature of conventional regulatory rate reviews make them inadequate to manage the scale, speed, and complexity of the historic transformation taking place in the electricity grid today. Forward-thinking regulators have begun looking for opportunities to update their tools and methods to better confront a growing and diversifying portfolio of proceedings, while still ensuring diligent analysis and customer protections.

This section highlights ways in which regulatory commissions can accomplish the following:

- Create additional flexibility and space for electric company innovation efforts
- Incorporate less formal, stakeholder-engaged processes to help foster consensus and resolve complex issues without significantly stalling regulatory progress

4.1 Regulatory Sandbox: Creating Space for Innovation

Innovation by nature is almost always in tension with regulation. Innovation requires testing unproven concepts and technologies, taking risks, and pursuing ideas that often fail. These tenets of innovation are at odds with both the obligations of electric companies (which are encouraged to avoid risks for safety, security, and reliability) and the duty of regulators to ensure a well-run and efficient electricity system. The question, then, is: What steps can be taken to encourage innovation within a regulated industry?

The regulatory sandbox concept was developed to address this uncertainty. These sandboxes are effectively a limited waiver from normal regulations and requirements, allowing companies with new innovative ventures to test their products or services in a constrained and safe environment. Having this flexibility is especially critical for the introduction of new customer offerings. It is not market responsive to conceive of a new customer solution and then wait a year or more for an adjudicated decision. In the time that traditional process takes place, the customer often will find another option. This same dynamic occurred in the telecom industry as competition increased for the incumbent wire line companies. Alternative regulation plans established expedited approval and introduction of new customer products and solutions.

While already popular in Europe, one of the first regulatory sandboxes in the US was created in Arizona for certain types of financial products and services. The FinTech Sandbox enables a participant to obtain limited access to Arizona’s market to test innovative financial products or services without first obtaining full state licensure or other authorization that otherwise may be required.[20]

In the electric company context, regulators could create space for electric companies to protype and test innovative products and services while establishing common-sense guardrails to ensure customer protection. Parameters that could be adopted include limitations on budgetary spend, program participants, and criteria limiting impact to non-participating customers. For instance, an electric company could be granted substantial leeway to create advanced pricing options and value-added services for customers so long as the prospective program does not: 1) exceed a certain budget amount; or 2) unreasonably shift costs from participants to non-participating customers.

Figure 4-1. Regulatory Sandboxes

Source: Guidehouse

One nascent application of the regulatory sandbox concept in the electric company context comes from Vermont. The regulator there has developed a promising policy tool to help drive innovation through an expedited implementation process for pilot programs that test new technologies, customer engagement, business models, and other arrangements.

Vermont's renewable energy standard requires the state's electric distribution electric companies to deliver "customer-facing transformative energy projects that decrease fossil-fuel consumption and greenhouse gas emissions" and requires the state's distribution electric companies to obtain "energy transformation credits (MWh)."[21] For Green Mountain Power (GMP), the state's only investor-owned electric company (IOU), these credits needed to equal 2.67% of its retail sales in 2018.[22] The Vermont PUC requires GMP and other utilities to submit annual plans on how they will obtain these energy transformation credits. GMP's innovative pilots help the electric company meet these credits.

[20] *See* "Welcome to Arizona's FinTech Sandbox," Arizona Attorney General, ***available at*** https://www.azag.gov/fintech.

[21] Vermont Department of Public Service, "Tier III – Renewable Energy Standard," ***available at*** https://publicservice.vermont.gov/content/tier-iii-renewable-energy-standard.

[22] These credits are calculated by converting avoided gallons of fuel resulting from GMP's eligible programs to MWh.

The Vermont PUC decided in 2014 to grant GMP approval to pursue innovative pilots on a non-tariffed basis.[23] GMP does not need commission approval prior to commencing these non-tariffed pilots but is required to provide written notice to the Vermont Department of Public Service, the commission, and Efficiency Vermont at least 15 days prior to commencing the pilot. GMP is then required to make periodic updates at 6-month intervals regarding the progress of a pilot program during its 18-month term.

GMP is required to include the costs and revenues of innovative pilots and services in base rate filings for review and approval. However, the Vermont PUC does not automatically guarantee rate recovery for all innovative pilot programs. If GMP wants to offer the product or service beyond the 18-month pilot term it must receive approval from the commission to offer it as a tariffed service.

GMP's current pilots focus on deploying and using new technologies to improve grid operations and to provide customers with new options to manage their energy use. These include:

- A pilot that provides Tesla Powerwall 2.0 batteries to residential customers for $15 a month for 10 years or a $1,500 one-time fee.[24] Using Tesla's software platform, GMP can control individual and aggregated batteries to reduce systemwide peak load to produce local grid benefits.
- A pilot that enables shared access to a customer's electric resistance water heater. Customers receive a retrofit kit manufactured by Aquanta that enables them to share access to their water heaters with GMP. Through this access, GMP can turn customer water heaters on and off (with opt out capability), or adjust the temperature up or down, in response to system needs. Participating customers also receive a Nest smart thermostat as a way to increase their energy savings.[25]

The New York REV demonstration projects offer another limited preview of how an electric company regulatory sandbox could be structured. In its 2015 Order Adopting Regulatory Policy Framework and Implementation Plan, the NY PSC directed the state's six large IOUs to develop projects intended to demonstrate the potential of the REV regulatory initiative. The electric companies submit and execute projects that test new business models and partnerships with third parties. REV demonstration projects aim to inform decision makers about developing Distributed System Platform functionalities, measure customer response to programs and prices associated with REV markets, and determine the most effective implementation of DER.

One REV demonstration project is the Con Edison Connected Homes Platform, launched in 2016. The platform provides approximately 275,000 eligible customers in Brooklyn and Westchester with detailed energy insights, targeted offers in Home Energy Reports, high usage alerts for solar panels, WI-FI thermostats, sealed home services, and access to the Con Edison Marketplace. Each quarter, Con Edison releases a report detailing updates on the platform's customer engagement and offerings, providing a record of information and insight for the electric company and broader community.

---

[23] Green Mountain Power, "Green Mountain Power Corporation Alternative Regulation Plan," June 2014. http://www.greenmountainpower.com/wp-content/uploads/2017/01/Alt-Reg-filed-June-4-2014.pdf.

[24] Green Mountain Power, *2018 Integrated Resource Plan*, Innovative Customer Programs, at 2.8-2.10.

[25] Green Mountain Power, *2018 Integrated Resource Plan*, Innovative Customer Programs, at 2.10-2.11.

4.2 Innovation Fund

The UK's RIIO framework includes an innovation stimulation package that funds research, development, and demonstration of new technologies and operating and commercial arrangements at both the distribution and transmission level. The funding is a complementary component to the other performance-based mechanisms that compose the UK's regulatory model and supports areas of innovation that could deliver benefits to consumers but are at risk of not being delivered through RIIO's other incentive mechanisms (e.g., payback is too long).

While there have been different iterations of the funding mechanisms over the years, Ofgem—the regulatory body that oversees the UK's distribution and transmission network operators (DNOs and TNOs)—currently operates an annual Network Innovation Competition (NIC), an annual Network Innovation Allowance, and an Innovation Roll-Out Mechanism.

For the NIC, distribution and transmission network companies submit projects for funding in partnership with other energy suppliers, universities, or technology providers. About $90 million is available annually for projects through the electricity NIC alone. These funds are collected as part of a transmission network system charge on customer bills. Network companies are also required to make a 10% non-refundable contribution to the costs of projects.[26] This contribution can come from the electric company or project partners but cannot be ratepayer money.

Two independent expert panels (one for electricity and one for gas) evaluate proposals and decide who to provide NIC funding. The panels assess each project against a set of evaluation criteria, including whether the project delivers environmental and financial benefits, generates knowledge that can be shared among all network companies, and involves other partners and external funding. To be eligible for the funding, network companies need to demonstrate that their proposed projects are new or different to avoid duplication. To ensure that the information acquired from these projects is shared with other network operators, receivers of NIC funding are required to submit annual progress reports and to present findings at events with other network companies. Examples of current NIC projects include a new method to assess the grid impact of EVs and a new approach to restore the electricity system using DER following a blackout.

4.3 Process to Advance New Products and Services

A third option to support innovative products and services is a web-based platform that connects the electric company with technology companies or other solutions providers. This approach has been used in New York through a centrally managed online portal called REV Connect.[27] REV Connect's goal is to help companies and electric companies deploy demonstration projects, new technologies, and diverse business models that advance New York's REV goals. REV Connect is currently led and funded by New York State Energy Research and Development Authority (NYSERDA), but its operators would like to institutionalize the process at

[26] Ofgem, "Electricity Network Innovation Competition," *available at* https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation/electricity-network-innovation-competition.

[27] "REV Connect," *available at* https://nyrevconnect.com.

companies.[28] The REV Connect team also includes subject matter experts from Guidehouse, New York Battery and Energy Storage Technology Consortium, and Modern Grid Partners.[29]

The REV Connect web-based portal connects technology companies with electric companies who have specific innovation needs. The REV Connect team assesses submissions against minimum requirements and consults with qualified submitters to better understand and improve their ideas. The team then summarizes these proposals for electric companies using evaluation criteria that includes the viability of the business model, electric company partnership structure, submitter capability, advancement of REV, and uniqueness of innovation. Electric companies and well-matched submitters then work (potentially with support from the REV Connect team) to develop a business model and partnership structure, and then to eventually gain necessary regulatory approvals. Examples of projects that have emerged from REV Connect include new business models for DC fast charging infrastructure and new thermal solutions, deployment and utilization of controllable water heaters, and a marketplace for community distributed generation.[30]

The REV Connect program includes Innovation Sprints that invite market players to submit ideas for a specific theme. The entire submission process is condensed into a 3-month timeframe to quickly transform ideas into projects. 2019 Innovation Sprints focused on: clean heating and cooling, electrifying transportation, and innovating energy efficiency.

4.4 Collaboration Over Litigation

Having the right policy tools to support the regulatory framework is important, but the design of the regulatory process is an often-overlooked element of successful modern electric company regulation. Process approach and docket design decisions frequently receive less attention than the technical and economic details of the regulatory mechanisms themselves. Absent a collaborative process approach, technical and economic decisions tend to get bogged down in adversarial debates and often produce inadequate, narrow outcomes. Well-designed processes can enable collaboration and catalyze consensus, while poorly designed processes have the potential to stagnate or lose focus on policy objectives.

Traditional approaches used in regulatory reviews—mostly quasi-judicial hearings and contested case proceedings consisting of back-and-forth filings between regulatory commissions, companies, and stakeholders—are often not up to the challenge of guiding participants through new, dynamic, and interrelated topic areas. The industry needs updated tools and methods to confront a growing and diversifying portfolio of proceedings while still ensuring protection of the public interest.

By embracing a less formal and more collaborative process design approach, such as that afforded by an investigatory proceeding, regulators can better engage stakeholders to explore grid needs or potential changes to the regulatory framework without the expectation of having to adopt a specific regulatory mechanism. The exploratory stage should have clear goals and strong moderation by credible experts to ensure a productive, collaborative, flexible stakeholder

---

[28] Walton, Robert. "Project of the Year: REV Connect," *Utility Dive*, December 3, 2018. https://www.utilitydive.com/news/rev-connect-project-of-the-year/539951/.

[29] Modern Grid Partners are utility consultants focused on grid modernization issues. See http://www.moderngridpartners.com/.

[30] "REV Connect Outcomes," *available at* https://nyrevconnect.com/rev-connect-outcomes.

discussion that will yield common understanding of grid needs and recommendations for solutions.

Investigatory processes can result in a variety of potential outcomes, including the issuance of a summary report that may encompass recommendations for policy development and for next steps by a commission. Investigatory processes can also lead directly to new decisional dockets where identified principles and recommendations for reform are translated into actual regulations and programs.

In Hawaii, the Hawaii Public Utilities Commission outlined a collaborative and stakeholder-driven approach that began with the collective development of regulatory goals and outcomes to guide PBR development. A series of three, stakeholder workshops helped to establish a common lexicon of terms and concepts, creating shared understanding about the existing regulatory framework. Participatory table-top exercises helped forge common ground between disparate parties and helped deliver relative consensus on numerous issues through Phase 1 of the proceeding.

5.0 Rate Design: Modern Rates for a Modern Grid

Customer friendly business model reforms can only go so far if the main interface with customers – pricing – remains unchanged. The current way customers are charged for electricity is increasingly misaligned with system costs and consumer preference. As the energy system becomes cleaner and more modernized, variable costs will decrease and fixed costs will increase. Unfortunately, under traditional cost of service, the rate design for many customers remains overly volumetric and non-time differentiated. Not only does this pricing not reflect the temporal nature of the electricity system or the largely fixed makeup of costs (poles, wires, meters, vegetation management, cybersecurity), but it also potentially discourages electrification as consumers would use electricity for more products.

Many jurisdictions across North America have implemented, or are considering, rate design reforms that better align rates and cost of service than simple, two-part rates (e.g., customer [fixed] and variable energy charges), such as those typically used for residential and small commercial customers.

Historically, analog meter technology for residential and small commercial customers limited the ability to offer more accurate and/or customer friendly rates. This historic approach to collecting electric company revenue has largely broken down—first, with the advent of energy efficiency goals and investments, and more recently, with the availability of AMI meters. Yet as technology has progressed, rate design has largely been static.

Enabled by the advanced capabilities of smart meters, rate design must evolve to help customers and their partners actively participate in the energy transition currently underway. The growth in interest in energy apps and home energy management means that some electric customers need information they can act upon in real time. Improved rate design can play an important role in facilitating and sustaining the companies’ role as a systems integrator and operator while cost-effectively enabling and encouraging a clean energy future.

5.2 Guiding Principles to Inform Advanced Rate Design

The development of advanced retail rates is guided by foundational rate design principles set forth through seminal works in the mid-20th century by authors including James Bonbright. Revised principles have been proposed by a variety of organizations to reflect 21st century conditions.

The following represents a harmonized set of guiding principles that may be considered and applied to modern rate design development:

- **Sufficiency:** Rates should be designed to produce enough revenue to recover electric company costs so that energy companies can continue to provide reliable service with a low cost of capital.
- **Fairness:** Rates should be designed to accurately incorporate the impact of customers' use on the system's cost of service. The cost of the grid should be fairly apportioned among customers such that there is no undue discrimination in rate relationships. Rates should be designed to accurately value both services provided by the grid and services received from customers.
- **Alignment:** Rates should support desired outcomes and compliment other electric company objectives aimed at enhancing customer choice and achieving specified policy goals.
- **Customer-centric:** Rates should be structured so that they can accommodate customer choice and facilitate adoption of new technologies, while also ensuring that vulnerable customers have access to affordable electricity.
- **Gradualism:** Rates should be implemented gradually over time so that changes do not cause large, abrupt increases in bills.

These principles require a balancing of sometimes competing interests. For example, developing cost-based fair rates free from subsidies could conflict with the principle of stability and predictability of the rates themselves. Developing economically efficient rates could conflict with customer acceptability if the rates become too unpredictable and the revenue sufficiency goal of the forward-looking, cost-based rates are materially different from the historical embedded cost-based rates.

5.3 Building Blocks for Advanced Rate Design

The transformation toward advanced rates can be viewed as increasing levels of sophistication along three spectra:

- **Temporal:** Where rates can evolve from unchanging flat rates to include time-differentiated prices that reflect benefits and costs that vary with time.
- **Attribute:** Where rates can unbundle and separately price the various sources of benefit and cost (e.g., energy, capacity).
- **Locational:** Where price signals can shift from standard systemwide values to prices that reflect site-specific costs and benefits.

Although increasing the sophistication of rates along one or more of these spectra can help send appropriate signals to adapt consumption behaviors to the evolving electricity system and customer needs, this enhanced granularity and complexity must be balanced against the guiding principles outlined in Section 6.1.

The following sections explore prominent and frequently proposed advanced retail rate design alternatives. These rate design categories can be thought of as building blocks that moderately increase sophistication from traditional rate structures as a means to recover sufficient costs while providing price signals that are more reflective of the electric company system actual cost.

5.3.1 Time-Varying and Dynamic Rate Design

Time-varying and dynamic rates include time-of-use (TOU) rates, critical peak pricing (CPP), peak-time rebates (PTR), multi-part time-variant rate design, and dynamic rates. Each design presents a different degree of price volatility and uncertainty for customers, but also presents a different opportunity to reduce their electric bill by shifting consumption from higher priced hours to lower priced hours.

5.3.1.1 Time-of-Use Rates

TOU rates (rates that vary based on time of day that correlates to peak or off-peak periods) provide customers with the appropriate price signals to encourage efficient use of electricity and deployment of DER. They offer customers the opportunity to lower their bills by shifting electricity use to when rates are the lowest or by offsetting demand via DER when rates are the highest.

A key advantage of TOU rates is that they separate historical costs of the system (customer- and demand-related) from the forward-looking short-run marginal costs driven by customer behavior and short-term energy usage. They achieve this with energy charges that reflect the marginal cost of providing power as well as non-volumetric charges to collect the historical embedded costs of service that do not vary with energy usage. For example, an energy charge could cover the cost of fuel and other variable costs involved in production; customer charges could cover the cost of the service drop, meter, and monthly billing; and grid usage charges could cover the grid's fixed cost. The grid usage charge may be measured based on demand or subscription service requests.

5.3.1.2 Critical Peak Pricing

Under a CPP rate, participating customers pay higher prices during the few days or hours when demand is the highest or when the power grid is severely stressed, typically up to 15 days per year during the seasons(s) of the system peak. This higher peak price reflects both the energy and longer-term capacity costs and, as a result of the capacity portion of those costs being spread out over relatively few hours of the year, can exceed $1/kWh. In exchange, CPP participants receive a discount on the standard tariff price during the other hours of the season or year to keep the electric company's total annual revenue constant. Customers are typically notified 1 day in advance of an upcoming critical peak event.

5.3.1.3 Peak-Time Rebate

PTR is essentially the inverse of CPP. It is a standard rate coupled with a rebate when customers reduce their usage during a peak demand event. Typically, if PTR customers do not want to participate in the called event, they simply pay the standard rate. There is no rate discount during non-event hours. While all forms of time-varying rates are designed to provide customers with the opportunity to save on their electric bill, PTR provides an increased level of bill protection because costs can only be reduced during the event.

5.3.1.4 Multi-Part Time-Variant Rate Design for Residential and Small Commercial Customers

An increasing number of electric companies are now offering a residential multi-part time-variant rate consisting of a customer charge, a volumetric charge (which can be time-variable), and a grid usage charge (which can also be time-variable). The grid usage charge collects revenue based on a customer's peak demand during a defined period. Grid usage charges (i.e., demand charges) have a long history of use by commercial customers, but only more recent experience with residential customers. The volumetric charge can be time-varying and dynamic, integrating one or more of the rate design structures outlined previously.

5.3.1.5 Dynamic Rates

Participants in dynamic rates programs pay for energy at a rate that is linked to the hourly market price for electricity. Participants are informed of hourly prices on either a day-ahead or hour-ahead basis. Dynamic rate programs communicate granular price signals that most accurately reflect the cost of producing electricity during each hour of the day, giving customers a precise incentive to reduce consumption at the most expensive times.

5.3.2 Subscription Pricing

Improved pricing can bring the benefits of many of the regulatory structures discussed previously and mimic the outcomes of decoupling and multiyear rates plans. Subscription pricing is one such example and is prevalent in many industries including, television, smartphones, transportation, and more. As the provision and billing of power services becomes more complex, energy providers could integrate this popular business model into their own services, making way for new technologies, changing customer preferences, and increased use of renewable energy sources.

An electric company subscription model, or energy service subscription plan (ESSP), would essentially enable customers to pay a fixed monthly bill for energy services. When combined with advanced analysis of customer interval load data and smart devices, customers can benefit from more choices, longer contract terms, and tailored offerings based on their preferences.

ESSPs can be beneficial to middle- and lower-income customers by improving their access to newer, more efficient technologies and appliances. Many of these customers cannot afford such investments, nor do they have access to credit at rates that would make such investments economical for them. If an electric company can provide these customers with newer, more efficient equipment and technologies in return for something akin to on-bill financing in the form of an ESSP, the electric company can recover its investment and participating customers can realize the increased convenience and comfort associated with these investments.

Figure 5-1. Example of an Energy Service Subscription Plan

	Unlimited Savings	Unlimited Choice	Unlimited Premium + EV
Fixed monthly price based on household profile usage (Your average current bill is $115/month)	$115/month for 36 months	$125/month for 36 months	$145/month for 36 months
30% Clean Energy with energy portal app	✓	✓	✓
100% Clean Energy	X	X	✓
Free Smart Thermostat	✓	✓	✓
Access to free or discounted energy efficiency upgrades	✓	✓	✓
Unlimited EV charging at home and in community	X	X	✓
Maximum number of control days	30	15	7
Free control day over rides per year	3	5	7

Note: This new pricing platform can allow the bundling of different smart home services, such as home monitoring, appliance warranty/maintenance programs, or other services, to further diversify the electric company's risk. This is similar to Amazon's interconnected subscription services in Prime (e.g., Prime Music, Delivery, Video, etc.).

Source: Guidehouse

Subscriptions focus on uses of the service rather than overall consumption. Targeting customer preference and needs based on behavioral data rather than kilowatt-hour transactions empowers electric companies to focus on increased customer choice, comfort, and convenience with a focus on high value outcomes.

5.3.3 Rate Combinations

The rate options described above can also be offered in combination to benefit from the relative advantages of each. One common combination is CPP and TOU. The TOU component of the rate reflects the average daily variation in peak and off-peak energy prices. The CPP component during a small percentage of hours each year reflects the cost of capacity during the seasonal system peak. Together, these rates can facilitate greater energy awareness among customers and provide greater opportunities for bill savings through a more heavily discounted off-peak rate. However, the added complexity of a combined rate design may require additional customer education to maximize the potential benefits and improve customer satisfaction.

7.0 Conclusion

The electric industry is in transition, driven by several key factors, from technological innovation and ambitious policy goals to the proliferation of renewable resources and the adoption of DER. Customers also are playing a key role in this transformation, as their preferences evolve and they demand new and different services from their electric companies.

As electric companies modernize their system to become smarter, cleaner, and stronger, regulators in many jurisdictions are finding that their traditional means of oversight may not be calibrated for the 21st century. To support decision makers as they weigh competing goals and objectives, this report provides a survey of alternative regulatory mechanisms that have emerged as tools to respond to evolving customer needs, as well as changing technological, policy, and market conditions.

This report does not purport to be a roadmap for the industry. Rather, it lays out a non-exhaustive set of options for those jurisdictions that seek to explore alternative regulatory approaches. Regulatory frameworks must be tailored for the specific characteristics of each jurisdiction. Where alternative regulation is an appropriate consideration, this report offers a suite of options that are being tested and applied and refined and revised, based on experience and outcome.

Many of the alternative regulatory mechanisms highlighted here have emerged to help create necessary space for innovation and to facilitate the better alignment of incentives within the regulatory model. This report surveys an array of different policy tools that can help address the challenges surfacing in traditional regulation. For certain jurisdictions, alternative regulatory mechanisms can often enhance customer experience while better aligning electric companies' financial incentives with the capabilities of new technologies and customer interests.

Appendix A.

A.1 Prevalence of Regulatory Mechanisms in the US

Table A-1. Prevalence of Revenue Decoupling in the US: 2019

Jurisdiction	Company
California	Bear Valley Electric Service
California	California Pacific Electric
California	Pacific Gas & Electric
California	PacifiCorp
California	San Diego Gas & Electric
California	Southern California Edison
Colorado	Public Service of Colorado
Connecticut	Connecticut Light & Power
Connecticut	United Illuminating
District of Columbia	Potomac Electric Power
Hawaii	Hawaiian Electric Company
Hawaii	Hawaii Electric Light Company
Hawaii	Maui Electric Company
Idaho	Idaho Power
Maine	Central Maine Power
Maryland	Baltimore Gas & Electric
Maryland	Delmarva Power & Light
Maryland	Potomac Electric Power
Massachusetts	Eversource Energy
Massachusetts	Fitchburg Gas & Electric
Massachusetts	National Grid
Minnesota	Northern States Power
New York	Central Hudson G&E
New York	Consolidated Edison
New York	New York State Electric & Gas
New York	Niagara Mohawk
New York	Orange & Rockland Utilities
New York	Rochester Gas & Electric
Ohio	AEP Ohio
Ohio	Duke Energy Ohio
Oregon	Portland General Electric
Rhode Island	Narragansett Electric
Vermont	Green Mountain Power
Washington	Avista
Washington	Pacific Power and Light
Washington	Puget Sound Energy

In addition to the MRPs listed below, at the time of this report's drafting, there are developing opportunities for multiyear rate plans elsewhere:

- The Maryland Public Service Commission has decided to adopt multiyear ratemaking.
- The Pennsylvania State Legislature has authorized the PUC to approve an MRP.

Table A-2. Prevalence of Multiyear Rate Plans in the US: 2019

Jurisdiction	Company
California	Bear Valley Electric Service
California	California Pacific Electric
California	Pacific Gas & Electric
California	PacifiCorp
California	San Diego Gas & Electric
California	Southern California Edison
Colorado	Public Service of Colorado
Connecticut	Connecticut Light & Power
Connecticut	United Illuminating
Florida	Florida Power & Light
Florida	Gulf Power
Georgia	Georgia Power
Hawaii	Hawaiian Electric Company
Hawaii	Hawaii Electric Light Company
Hawaii	Maui Electric
Iowa	MidAmerican Energy
Massachusetts	Eversource
Massachusetts	National Grid
Minnesota	Northern States Power
New Hampshire	Eversource Energy
New Hampshire	Unitil Energy Systems
New York	Central Hudson Gas & Electric
New York	New York State Electric & Gas
New York	Consolidated Edison
New York	Niagara Mohawk
New York	Orange & Rockland Utilities
New York	Rochester Gas & Electric
North Dakota	Northern States Power
Ohio	First Energy Ohio
Washington	Puget Sound Energy

Table A-3. Prevalence of Formula Rates in the US: 2019

Jurisdiction	Company
Alabama	Alabama Power
Arkansas	Entergy Arkansas
Illinois	Ameren Illinois
Illinois	Commonwealth Edison
Louisiana	Cleco Power
Louisiana	Entergy Louisiana
Louisiana	Southwestern Electric Power
Mississippi	Entergy Mississippi
Mississippi	Mississippi Power

Table A-4. Prevalence of Performance Incentive Mechanisms in the US: 2019

States with Some Form of Performance Incentive Mechanisms
California
Connecticut
District of Columbia
Hawaii
Illinois
Massachusetts
Michigan
New Hampshire
New Mexico
New York
Rhode Island
Vermont

Table A-5. Prevalence of Performance-Based Regulation in the US: 2019

Jurisdiction	Status
Colorado	Exploring PBR options with inquiries and/or reports
District of Columbia	Initial stakeholder engagement
Hawaii	Advanced stakeholder engagement
Illinois	PBR currently or soon to be implemented
Maine	PBR currently or soon to be implemented
Maryland	Exploring PBR options with inquiries and/or reports
Massachusetts	PBR currently or soon to be implemented
Michigan	Initial stakeholder engagement
Minnesota	Advanced stakeholder engagement
Nevada	Exploring PBR options with inquiries and/or reports
New Hampshire	Initial stakeholder engagement
New Mexico	Exploring PBR options with inquiries and/or reports
New York	PBR currently or soon to be implemented
Ohio	Exploring PBR options with inquiries and/or reports
Oklahoma	Decided not to pursue

Jurisdiction	Status
Oregon	Exploring PBR options with inquiries and/or reports
Pennsylvania	Initial stakeholder engagement
Rhode Island	PBR currently or soon to be implemented
Texas	Decided not to pursue
Vermont	Exploring PBR options with inquiries and/or reports
Washington	Exploring PBR options with inquiries and/or reports

About the Authors

David O’Brien

David O’Brien is a Director in Guidehouse’s Energy, Sustainability, and Infrastructure practice. With over 30 years of serving as an energy policy and business strategist, his diverse portfolio of executive experience spans commercial finance, economic development, electric company regulation, and strategy consulting. Throughout his career, O’Brien has helped organizations reform in the face of increasing customer expectations and technological sophistication. His work on behalf of Guidehouse clients has centered around exploring new regulatory systems and business practices that are part of a changed electric company business model.

Matthew McDonnell

Matthew McDonnell is a Director with Strategen, and formerly with Guidehouse, who contributed heavily to the drafting of this paper. Matthew leveraged his prior experience as a state regulator to deliver valuable insights to clients.

An expert in electric company regulation and energy policy, Matthew led or supported a variety of energy projects including, regulatory strategy for an energy storage manufacturer; advanced demand response program development; integration of DER; and the development of advanced performance-based regulatory frameworks. Matthew has deep regulatory experience in leading-edge markets and appreciates the broad perspectives of the industry’s diverse stakeholders.

Matthew earned his JD from the University of Arizona and a B.A. in Finance from Michigan State University. He is licensed to practice in both Arizona and Hawaii.

Hope Lorah

Hope Lorah is a consultant in the Guidehouse’s Energy, Sustainability, and Infrastructure practice, supporting energy industry stakeholders through economic, policy, and technology transitions in the industry. Her work includes energy regulation and policy, business strategy, and program design and implementation. Lorah also has experience in DSM programs, renewable resource procurement, and DER markets including energy storage, solar, microgrids, and EVs.

Hope received her BS in Civil and Environmental Engineering from Princeton University.

About Guidehouse

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges with a focus on markets and clients facing transformational change, technology-driven innovation and significant regulatory pressure. Across a range of advisory, consulting, outsourcing, and technology/analytics services, we help clients create scalable, innovative solutions that prepare them for future growth and success. Headquartered in Washington DC, the company has more than 7,000 professionals in more than 50 locations. Guidehouse is led by seasoned professionals with proven and diverse expertise in traditional and emerging technologies, markets and agenda-setting issues driving national and global economies. For more information, please visit: www.guidehouse.com.