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2022 PSE GENERAL RATE CASE
WITNESS: MARK NEWTON LOWRY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-22____** **Docket UG-22____**

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

MARK NEWTON LOWRY

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

Performance-Based Regulation for Puget Sound Energy

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Contents

Executive Summary

New legislation in Washington encourages performance-based rate making for electric and gas utilities. Utilities are now required to propose multiyear rate plans in their general rate cases. These plans must include performance metrics and targeted incentives. Puget Sound Energy is filing for new rates and MYRPs for its electric and gas services in this proceeding.

Pacific Economics Group Research LLC is a leading consultancy in the performance-based regulation field. Puget Sound Energy has asked us to help it develop metrics and incentive mechanisms for its multiyear rate plan. We have also been asked to prepare this report and expert witness testimony on performance-based regulation, the performance metrics in the Puget Sound Energy multiyear rate plan, and an appraisal of that plan.

What is Performance-Based Regulation?

Performance-based regulation is the name given to a group of popular alternatives to traditional cost of service ratemaking. These alternatives have in common a tendency to encourage better utility operating performance. Four approaches to performance-based regulation are well-established.

- Revenue decoupling weakens the link between a utility's earnings and the use of its system by customers. This eliminates the throughput incentive that discourages utilities from embracing demand-side management. It also reduces the risk of rate designs that facilitate demand-side management.
- Metrics monitor key performance areas and can be used to strengthen incentives in these areas.
- Some performance-based regulation provisions target desirable practices such as demand-side management that utilities tend to underuse. These provisions include pilot programs and trackers for the costs of these practices.
- Multiyear rate plans reduce the frequency of general rate cases and can strengthen cost containment incentives and streamline regulation. Between rate cases, growth in allowed revenue may be based on cost forecasts, index formulas, or a hybrid of the two. When capital cost is forecasted, some plans provide refunds if a utility's actual capital cost is lower.

Performance metrics quantify aspects of utility operations which matter to customers and the public. Target values may be established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. Scorecards summarizing results for key metrics are often tabulated and may be posted on a publicly-available website. Performance incentive mechanisms can link revenue to the outcomes of performance appraisals based on metrics.

Performance incentive mechanisms can strengthen financial incentives for utilities to perform better in targeted areas that matter to regulators, customers, and the general public. They are useful for addressing "weak spots" in regulatory system incentives. Many observers are concerned that traditional ratemaking provides weak incentives for utilities to contain environmental damage from their operations. This helps to explain the interest of environmental intervenors in Performance Incentive Mechanisms.

The basic approaches to performance-based regulation can be combined. For example, multiyear rate plans often include the other three performance-based regulation approaches. The stronger incentives that performance-based regulation provides can encourage better performance, and benefits can be shared between utilities and their customers.

All four performance-based regulation approaches have been used by the Washington Utilities and Transportation Commission. For example, Puget Sound Energy has had multiyear rate plans on two previous occasions, and currently has revenue decoupling and service quality metrics and Performance Incentive Mechanisms. The Washington Utilities and Transportation Commission's performance-based regulation experience increases the likelihood that it will oversee its expanded use effectively.

Puget Sound Energy's Proposed Multiyear Rate Plan

Puget Sound Energy's multiyear rate plan proposal is in line with Washington statute, Commission policies, and established precedents. Here are some salient plan provisions.

- The term of the plan would be three years.
- Revenue in the first year would be established in the rate case Puget Sound Energy files in January 2022. Escalation of base revenue would be driven in the next two years by Puget Sound Energy's five-year financial plan. Of the various established approaches to multiyear rate plan revenue escalation, this one is most consistent with the new Washington statute.
- The portion of the proposed revenue requirement that is tied to projections of the value of assets that are expected to become used and useful during the plan would be subject to refund pending regulatory review. This provision is consistent with established Washington Utilities and Transportation Commission policy regarding such assets.
- Revenue decoupling would continue for the gas and electric services of residential and most business customers.
- Any surplus earnings exceeding 50 basis points would be deferred for refunds to customers or another determination by the Washington Utilities and Transportation Commission in a later proceeding.
- The various low-income provisions of the plan include a new rate for low-income customers.
- The plan would contain a shortlist of performance metrics and performance incentive mechanisms that are appropriate for tracking Puget Sound Energy's performance during the plan and for encouraging good performance. Results would be posted on a publicly-available scorecard. The following table is a draft scorecard that includes all of the proposed

metrics. Several metrics address demand-side management, the management of electric vehicle loads, and benefits to highly impacted communities and vulnerable populations.

We believe that the proposed plan will strengthen Puget Sound Energy's performance incentives. Good performance will also be encouraged by statutory directives to pursue all cost-effective demand-side management, decarbonize operations, and share benefits with disadvantaged customers. The numerous customer protections encourage a fair balance between utility and customer interests.

Streamlined regulation can free up resources in the regulatory community to concentrate on capital spending, the clean energy plans, and the continual string of complicated generic issues that are surfacing in this age of rapid change. The extent of improvements in the efficiency of regulation will depend on the Washington Utilities and Transportation Commission's multiyear rate plan implementation decisions. Whereas recent laws in some states mandate a specific approach to alternative regulation, the Washington Utilities and Transportation Commission has considerable discretion over its implementation in Washington.

Proposed PSE Scorecard

Current SQI Metrics

Category	Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Customer Satisfaction	Complaints per 1,000 Customers to the WUTC	0.18	0.2	0.16	0.16	0.1		Less than 0.4
	Customer Access Center Transactions Customer Satisfaction	93%	93%	94%	92%	94%		At least 90%
	Field Service Operations Transactions Customer Satisfaction	95%	94%	95%	95%	96%		At least 90%
Customer Service	Calls Answered by a Live Representative Within 60 Seconds of Request*	82%	82%	81%	81%	84%		At least 80%
	Percent of Appointments Kept	100%	100%	100%	100%	99%		At least 92%
Gas Safety	Average Gas Safety Response Time	31 minutes	32 minutes	30 minutes	32 minutes	32 minutes		No more than 55 minutes
Electric Safety	Average Electric Safety Response Time	55 minutes	55 minutes	52 minutes	54 minutes	51 minutes		No more than 55 minutes
Electric Reliability	SAIFI All Outages Current Year ($SAIFI_{TOTAL}$)	1.70 interruptions	1.80 interruptions	1.57 interruptions	1.57 interruptions	1.70 interruptions		No Target
	SAIFI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days (New $SAIFI_{SQI-4}$)	1.00 interruptions	1.12 interruptions	0.99 interruptions	0.98 interruptions	1.04 interruptions		1.2 interruptions
	SAIDI All Outages Current Year ($SAIDI_{TOTAL}$)	391 minutes	477 minutes	438 minutes	550 minutes	414 minutes		No Target
	SAIDI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days ($SAIDI_{SQI-3}$)	148 minutes	175 minutes	145 minutes	136 minutes	165 minutes		155 minutes

New SQI Metrics

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
SAIFI for HIC and VP, All Outages, Single Year	1.12	1.31	1.13	1.18	1.35		No Target
SAIFI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	0.75	0.88	0.77	0.74	0.84		No Target
SAIDI for HIC and VP, All Outages, Single Year	249	331	351	427	340		No Target
SAIDI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	105	143	116	111	141		No Target

Demand-Side Management

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Peak Load Management Savings (MW)	N/A	N/A	N/A	N/A	N/A		5
Peak Load Management Savings (MW) Attributable to Residential Customers	N/A	N/A	N/A	N/A	N/A		No Target
Annual Energy Efficiency Savings - Electric (MWh)	314,526	318,316	299,918	237,925	221,001		239,026
Annual Energy Efficiency Savings - Gas (Therms)	4,480,141	3,613,600	3,771,307	3,228,159	4,102,810		3,572,307
Number of Customers Participating in Gas and Electric Energy Efficiency Programs (Including Low-Income Programs) Who are from Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target

Electric Vehicles

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Number of Light-Duty Electric Vehicles in Service Territory	NA	NA	NA	NA	NA		No Target
Number of EV Chargers Used in Managed Load Programs or TOU Rates (Single-Family Residential)	NA	NA	NA	NA	NA		5,000
Number of EV Chargers Used in Managed Load Programs or TOU Rates (Fleet)	NA	NA	NA	NA	NA		47
Number of Public Charging Ports Serving HIC and VP	NA	NA	NA	NA	NA		No Target

Greenhouse Gas Emissions

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
CO2 Emissions from Company-Owned Electric Operations	6,515,902	6,217,840	6,080,674	7,406,110	4,793,992		No Target

Advanced Metering Infrastructure

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
AMI Bill Read Success Rate - Electric	NA	NA	NA	99.68%	99.76%		No Target
AMI Bill Read Success Rate - Gas	NA	NA	NA	99.40%	99.43%		No Target
Remote Switch Success Rate	NA	NA	NA	NA	99.41%		No Target
Reduced Energy Consumption from Voltage Reductions (kWh)	3,319,625	0	2,127,882	343,748	3,931,329		6,000,000

Additional Equity Metrics

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Number of Low-Income Customers Receiving Bill Assistance (Gas and Electric)	NA	NA	NA	NA	NA		No Target
Share of Bill Assistance Customers who are in Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target

Values of "NA" indicate that historical data are not readily available. "No target" indicates that no target has been established for that metric in that year.

*In 2016 and 2017 this metric was the percentage of calls answered in 30 seconds. The target for this metric was 70%. The data reported for these years are consistent with the current metric.

1. Introduction

Senate Bill 5295 provides for a transformation of energy utility regulation in the state of Washington towards multiyear rate plans ("MYRPs") and performance-based regulation ("PBR").[1] Section 1 of the bill directs the Washington Utilities and Transportation Commission ("UTC" or "the Commission") to conduct a proceeding to develop a policy statement on PBR and other alternatives to traditional ratemaking. Section 2 requires utilities to propose MYRPs in each general rate case. Puget Sound Energy ("PSE" or "the Company") is filing a rate case and MYRP proposal in this proceeding.

Pacific Economics Group Research LLC ("PEG") is a leading North American PBR consultancy. Our personnel have been active in the field since 1989. Working for a mix of utilities, trade associations, regulators, government agencies, and consumer and environmental groups has given our practice a reputation for objectivity and dedication to good regulation. We recently wrote a paper on MYRPs for Lawrence Berkeley National Laboratory[2] and have conducted several surveys of alternative regulation ("Altreg") for the Edison Electric Institute.[3] The Company retained PEG to help it develop metrics and performance incentive mechanisms for its proposed MYRP. PSE has also asked us to prepare a report that provides an overview of MYRP plan design and discusses metrics and other provisions of the Company's proposed MYRP.

This is the requested report. We begin with a discussion of the traditional cost of service approach to regulation and its suitability for addressing modern business conditions. This motivates a discussion of PBR alternatives such as MYRPs and performance metric systems. We then consider the current regulatory system of PSE and its MYRP proposal. An Appendix includes a glossary of ratemaking terms.

[1] Terms defined in the Glossary of Terms are underlined in this report.

[2] Lowry, M.N., Makos, M., Deason, J., and Schwartz, L., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," for Lawrence Berkeley National Laboratory, Grid Modernization Laboratory Consortium, U.S. Department of Energy, July 2017.

[3] See, for example, Lowry, M. N., Makos, M., and Waschbusch, G., 2015. "Alternative Regulation for Emerging Utility Challenges: 2015 Update," for Edison Electric Institute.

2. Traditional Utility Ratemaking and the PBR Alternative

In this section of the report we consider alternative approaches to utility regulation. We first discuss traditional cost of service ratemaking. We then provide a critique of this traditional approach which focuses on its ability to produce good results under modern business conditions. PBR and other alternatives to traditional ratemaking are then introduced.

2.1 A Critique of Traditional Ratemaking

The traditional approach to energy utility ratemaking in North America is commonly called cost of service regulation ("COSR"). This approach has the following essential characteristics.

- A base revenue requirement is established in rate cases which reflects the costs that the utility has recently incurred or is forecasted to incur for capital, labor, materials, and services. The cost of service includes a pro forma return on the depreciated value of plant. Rates are designed for each service class to recover the portion of the revenue requirement which is allocated to that class. Utilities are typically free to file rate cases as needed to address financial attrition. The timing of these cases is irregular.
- Cost trackers expedite recovery of energy commodity expenses because these are large and volatile. Balancing accounts are typically used to track unrecovered costs that regulators deem prudent. Recovery of these costs is then typically initiated promptly using rate riders.[4]
- Costs are sometimes deemed imprudent by regulators and disallowed.
- Rate designs are expressly approved by the regulator and may reflect a range of considerations that include affordability, cost causation, and appropriate price signals to inform customer usage decisions. Legacy base rate designs typically have high usage charges that recover a sizable share of utility costs that are fixed in the short run. If utilities have excess capacity they then earn a profitable margin from increased system use between rate cases.

COSR fulfills several key functions of utility regulation. Setting revenue equal to cost, including a reasonable return on capital, is fair, reduces operating risk, and ensures that customers receive most benefits of utility operations. Target rates of return can be lower than in competitive markets, a benefit for customers that is amplified by the capital-intensive technology.

In a recent white paper for Lawrence Berkeley National Laboratory we explained, however, that the efficacy of COSR varies with the business conditions that utilities face.[5] To the extent that key business conditions favor utilities on balance, their revenue growth between rate cases roughly matches their cost growth. This reduces the need for rate cases. Infrequent rate cases strengthen the

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[5] Lowry, M.N., Makos, M., Deason, J., and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

performance incentives of utilities by affording them more time to benefit from efforts to reduce the cost of base rate inputs. Customers benefit from base rates that are unchanged in nominal terms and falling in real terms. Regulatory cost is low.

When business conditions are chronically unfavorable, on the other hand, the utilities' costs tend to grow faster than their revenue. Rate cases without fully-forecasted test years that anticipate this challenge then tend to be undercompensatory. Utilities file rate cases more frequently. This weakens their cost containment incentives and raises regulatory cost.

It is also noteworthy that electric utilities deliver and, in many parts of North America, also produce a commodity that is still chiefly generated from combustion of fossil fuels, while gas utilities deliver fossil fuel to customers to burn on their premises. Production and consumption of fossil fuels harms the environment but, in the United States, the cost of this damage is for the most part external to utility finances. COSR thus entails weak utility incentives to reduce harmful emissions.

Utility operations may also produce positive externalities. For example, the local community may benefit from the retention of a large industrial load or from forms of generation that rely more on labor and other local inputs. The failure of utilities to capture extra benefits of their actions may cause them to do too little to create these benefits.

2.2 COSR Under Modern Business Conditions

Key business conditions that affect the frequency of rate cases are considerably less favorable on balance for the typical U.S. energy utility than they were in the decades before 1970 when COSR became a tradition. Between World War II and the late 1960s, brisk growth in the use of gas and electric grids boosted the utilization of grid capacity and accelerated the realization of scale economies. This helped utilities self-finance cost growth. Inflation was generally slow. We call this period the "golden age" of COSR because this regulatory system worked well under these conditions.

In recent years, however, there has been mounting concern about greenhouse gas ("GHG") and other harmful emissions from the production of electricity and the production, delivery, and consumption of natural gas. For this and other reasons, policymakers and many utility customers have had an increased interest in demand-side management ("DSM") and the use of cleaner energy resources (e.g., solar, wind) to generate power. Many American states now have renewable portfolio standards for electric utilities and several states have recently added aggressive decarbonization goals.

DSM and sluggish economic growth have materially slowed growth in grid use. In a few states, like Arizona, California, and Hawaii, growth in the amount of power produced at central locations and delivered by the grid has been materially slowed by the growth of distributed generation and storage ("DGS") behind customer meters. DSM and DGS are sometimes grouped under the heading of distributed energy resources ("DERs"). For all of these reasons, growth in the average use of gas and electricity by U.S. residential and commercial customers is typically negative today. Under legacy rate designs this materially slows revenue growth. Growth in system use varies with local economic growth, weather, DGS penetration, and DSM programs.

The need for capital expenditures also varies. Some utilities today need sustained high distribution capex to replace aging facilities and/or to improve system reliability, resiliency, and safety. Technological change has created opportunities for advanced metering infrastructure ("AMI") and other "smart grid" capex that can improve system performance.[6] These kinds of capex don't produce much automatic revenue growth.

When sluggish growth in system use combines with sustained high system modernization capex, utilities need brisk and continual escalation in rates. When rate cases do not use forward test years, rates may be uncompensatory. Under COSR this results in frequent rate cases that weaken cost containment incentives and raise regulatory cost.

Regulatory resources that are currently devoted to electric rate cases are getting stretched thin in this era of rapid change. For example, it is a major effort for regulators to appraise grid modernization and clean energy proposals. Modern conditions also provide new reasons to afford utilities more marketing/pricing flexibility. There is growing interest in green power packages and in miscellaneous new rates and services that may be enabled by smart grid technologies. Other issues raised by contemporary operating conditions include rate designs and compensation to DGS customers for their power surpluses.

2.3 PBR and Other COSR Alternatives

Problems with COSR have for many years spurred interest in alternative approaches to rate regulation. These approaches are sometimes referred to collectively as alternative regulation or "Altreg." With cost growth tending to exceed revenue growth, utilities have naturally championed Altreg approaches that accelerate revenue growth. These approaches have included forward test years, diminished roles for volumetric charges in rate designs, and expanded use of trackers to address rapidly growing costs of base-rate inputs. Formula rate plans, which essentially track all costs, are now used in several American states in retail energy utility ratemaking.

The various Altreg approaches can be evaluated using criteria that include regulatory efficiency, the utility performance incentives they generate, and their ability to strike a fair balance between utility and customer interests. PBR is the group of ratemaking approaches with relatively strong performance incentive properties. There are four well-established PBR approaches.

- Revenue decoupling reduces the throughput disincentive to embrace DERs.
- Performance incentive mechanisms target weak points in a utility's incentive structure.
- Some PBR provisions expressly encourage desirable practices that utilities tend to underuse.
- MYRPs reduce the frequency of rate cases and can strengthen cost containment incentives.

[6] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

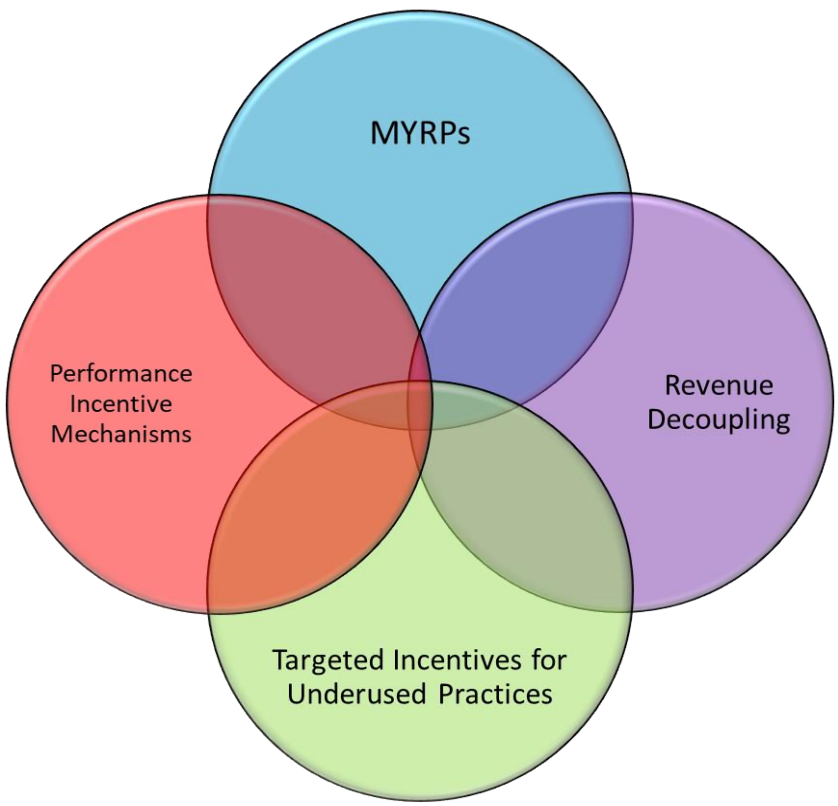
The stronger incentives provided by PBR can encourage better performance. Some PBR approaches have other benefits that encourage their use. For example, MYRPs can streamline regulation and facilitate greater utility operating flexibility.

The combined effect of these attributes is a regulatory process that, despite lower cost, can strengthen performance incentives and afford an increase in operating flexibility. The potential benefits from rate regulation are therefore increased and PBR plans can be designed so the benefits of performance improvements are shared between shareholders and customers.

The four established approaches to PBR can be and frequently are combined, as Figure 1 illustrates. One reason for these combinations is that the individual tools may not by themselves satisfactorily address all incentive problems. Another is that some tools can produce undesirable side effects that other PBR tools can counteract. In Sections 3-6 of this report we discuss each of the major PBR approaches and the ways that they interact in some detail.

Figure 1

PBR Approaches are Frequently Combined



3. Relaxing the Revenue/Usage Link

3.1 Introduction

Regulators are increasingly interested in relaxing the link between a utility's revenue and the use of its system by customers. This is a form of PBR because it reduces incentives that utilities may otherwise have to boost the utilization of their systems (aka "throughput"). We noted in Section 2.1 that utilities generally profit from increased capacity utilization under legacy rate designs, with their high usage charges. Even when demand growth taxes capacity there may be profitable investment opportunities, and utilities are largely indifferent to the growth in externalities that demand growth entails. Higher system use is undesirable to the extent that alternatives to higher use such as DERs are less costly. A diminished <u>throughput incentive</u> reduces the disincentive utilities otherwise have to facilitate use of DERs. Relaxation of the revenue/usage link can also address any problem of declining average use that the utility is experiencing. The frequency of rate cases can to that extent be reduced, thereby strengthening cost containment incentives and reducing regulatory cost.

Two methods are widely used in North America for relaxing the revenue usage link: revenue decoupling and lost revenue adjustment mechanisms ("LRAMs"). We confine our discussion here to the revenue decoupling option.

3.2 Revenue Decoupling

Revenue decoupling adjusts a utility's rates mechanistically to help its *actual* revenue track its *allowed* revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a <u>revenue adjustment mechanism</u> ("RAM"). The RDM tracks variances between actual and allowed revenue and adjusts rates periodically to reduce them. A rate rider is commonly used to draw down these variances by raising or lowering rates.

The RAM escalates allowed base rate revenue to provide relief for cost pressures. The great majority of decoupling systems have some kind of RAM since, if allowed revenue is static, the utility will experience financial attrition when the cost of its base rate inputs rises. Costs of base rate inputs typically do rise due to forces such as input price inflation, customer growth, and the need for facility modernization.

When utilities do not have multiyear rate plans, RAMs approved in the United States typically escalate allowed revenue only for customer growth.[7] While this is helpful, the cost of most U.S. energy utilities is driven more by input price inflation than by customer growth. Accordingly, it would be reasonable for RAMs to escalate allowed revenue for price inflation instead of customer growth.

[7] Escalation for price inflation would be a reasonable alternative.

The potential benefits of revenue decoupling are numerous. Decoupling can eliminate the lost-margin disincentive for a wide array of utility initiatives to encourage DERs, without relying on complicated load impact calculations or rate designs with high fixed charges that could discourage DERs.[8] For example, decoupling reduces the risk from offering customers time-sensitive usage charges that shift loads away from periods of peak congestion. Decoupling can also compensate utilities for reduced usage-charge revenue due to the DSM programs of government agencies. Because it encourages a wide range of DSM initiatives and DGS, environmental intervenors are typically strong supporters of decoupling. Rate cases are less frequent to the extent that overall growth in billing determinants is less than customer growth (due, for example, to declining average use). Decoupling also reduces controversy over billing determinants in rate cases with future test years.

Revenue decoupling may not be desirable for all services. For example, some customers may have a demand that is particularly sensitive to the terms of utility services. This category includes industrial establishments that have a choice between utilities and consume large amounts of energy. Electrification of motor vehicles and space heating can produce positive environmental impacts and permit reductions in rates to other customer classes. Utilities under decoupling may be insufficiently attentive to retaining and growing these kinds of loads.

Quite commonly, only revenues from residential and smaller commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue and are often the primary focus of DSM programs. The incentive to promote electrification of transportation could in principle be strengthened by decoupling only a fraction of the resulting base rate revenues.

States that have recently utilized revenue decoupling for electric and gas utilities are indicated on the maps below in Figures 2a and 2b, respectively.[9] In the electric utility industry, it can be seen that decoupling is currently used in 19 jurisdictions. DSM is aggressively encouraged by policymakers in many of these jurisdictions. Decoupling is even more widespread in the gas distribution industry. This reflects the fact that gas distributors have for many years experienced declining average use.

[8] Load impact calculations may nonetheless be undertaken to help ascertain the effectiveness of DSM programs.

[9] The maps reflect the status of decoupling circa March 2021.

Figure 2a

Recent Electric Revenue Decoupling Precedents in the United States

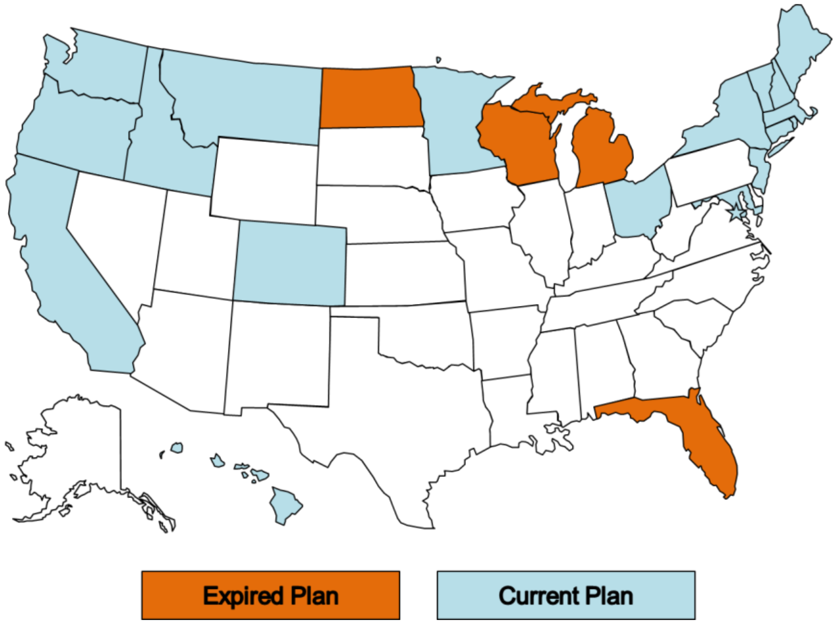
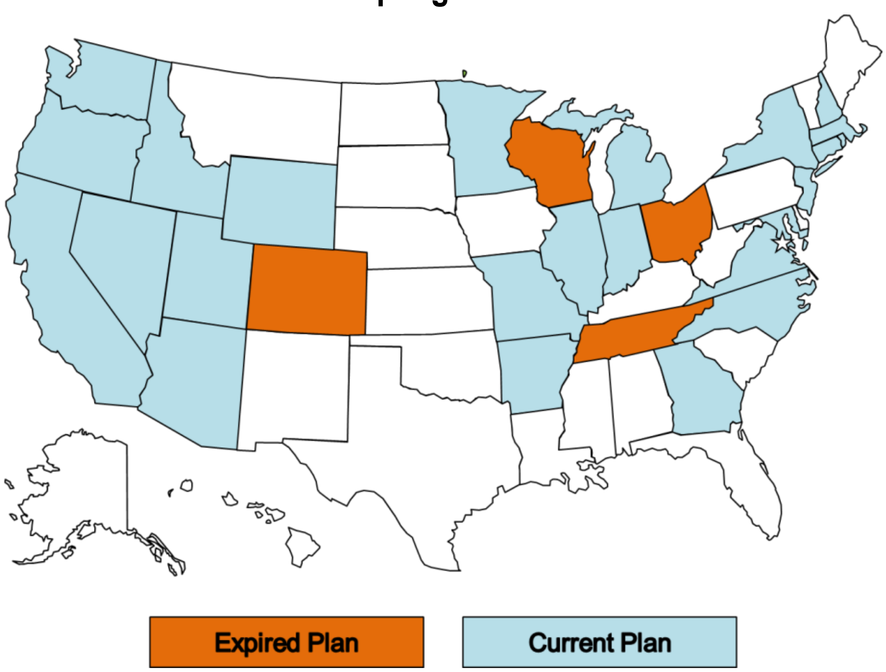


Figure 2b

Recent Gas Revenue Decoupling Precedents in the United States



4. Performance Metric Systems

4.1 The Basic Idea

Performance metrics quantify aspects of utility operations which matter to customers and the public. A performance metric system is a system for routinely monitoring select metrics and using them in performance appraisals. Target (aka "benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. Scorecards summarizing results for key metrics are often tabulated and may be posted on a publicly-available website or included in customer mailings.

Quantitative performance appraisals using metrics are sometimes used in ratemaking. A performance incentive mechanism ("PIM") can, for example, link revenue mechanistically to the outcomes of performance appraisals based on metrics. These revenue adjustments can be made in rate cases and/or between rate cases. The following simple mechanism for a hypothetical utility called Western Power is one example of how a PIM can be designed:

$$\textit{Revenue Adjustment}^{Western} = \$ \times (SAIFI^{Western} - SAIFI^{Target}).$$

Here, a system average interruption frequency index ("SAIFI") is the performance metric. The SAIFI value attained by Western is compared to a target. The term "\$" is the award/penalty rate per unit of deviation from the target. If Western meets the target, then $SAIFI^{Western}$ equals $SAIFI^{Target}$ and the revenue adjustment is zero. If Western performs better than the benchmark, the company may increase its revenue. By the same token, if Western underperforms it must decrease its revenue.

4.2 Metrics

Various kinds of metrics are used in ratemaking.

- Outcome (aka output) metrics quantify aspects of utility operations that directly affect the welfare of customers & society. Examples include reliability, the cost of service, and GHG emissions. A focus on what ultimately matters is one advantage of these metrics. Since improvement in performance can typically be achieved by several means, the utility has more freedom to choose between these means.
- A net benefit metric takes the difference between program benefits and costs. A PIM that is based on such a metric can then be designed to share net benefits. However, net benefit metrics tend to be limited to programs with measurable costs and benefits. Moreover, these calculations may be complicated and controversial.
- Another kind of metric gauges actions and characteristics that tend to promote desirable outcomes. Metrics of this kind are especially useful when metrics of the kinds just discussed are impractical. For example, it is much easier to measure the number of customers participating in a time-of-use ("TOU") pricing program than it is to measure the net benefits of such a program.

4.3 Popular Areas for PIMs

Service Quality

Service quality is one of the most common areas of utility operations where metrics and PIMs are used in utility regulation. Service quality metrics for energy utilities have traditionally fallen into three general categories: reliability, customer service, and safety. Service quality PIMs can strengthen incentives to maintain or improve quality and simulate the connection between revenue and product quality that firms in competitive markets experience. The need to bolster service quality incentives is greater to the extent that a utility has strong cost containment incentives. Service quality incentives are therefore commonplace in multiyear rate plans, as discussed further in Section 6 below.

Reliability metrics used in utility regulation commonly feature measures that summarize systemwide outage frequency and duration and may also feature regional or local reliability metrics. System reliability metrics most commonly provide the basis for PIMs. The most common system reliability metrics used in PIMs are SAIFI and the system average interruption duration index ("SAIDI"). Customer service metrics include summaries of customer satisfaction surveys, customer complaints to the regulator, billing accuracy, and the ability of the utility to keep its field appointments. Performance using reliability and customer service metrics is usually assessed through a comparison of a company's current year performance to its recent historical performance.

Energy Efficiency

The Basic Idea

Energy efficiency ("EE") PIMs tie the revenue of a utility to indications of success in its EE programs. Performance metrics in such PIMs include the MWh of load. The focus is typically on the load savings attributable to EE.

The success of a utility EE program depends partly on the MWh of load savings achieved and partly on program cost per kWh saved. Some energy efficiency PIMs therefore have a "shared savings" format that can guard against excessive program cost. Net benefits of programs are calculated, and these are shared mechanistically between utilities and their customers.

PIMs can strengthen utility incentives to embrace energy efficiency. Revenue decoupling can remove the throughput disincentive to resist EE whereas EE PIMs can provide a *positive* incentive where this might be weak because EE reduces capex opportunities or because environmental damage is external to the company's finances.

However, EE PIMs also have some challenges. Estimation of load savings from EE programs and their cost impact is generally complicated and can be controversial. Independent verification of savings has sometimes been required. Energy efficiency PIMs therefore typically exclude many kinds of DSM programs (e.g., customer information programs). In this situation, utilities are incentivized to focus on programs addressed by the PIMs and may neglect initiatives that aren't addressed by them.

Precedents

The American Council for an Energy Efficient Economy has found that targeted incentives (e.g., management fees) for DSM are quite common in the United States.[10] In their 2020 State Energy Efficiency Scorecard, they reported that 29 states had some form of performance incentives for electric DSM programs and 17 states had performance incentives for gas DSM programs.[11] The incentives encompassed management fees as well as PIMs.[12] Among DSM PIMs, those focused on energy efficiency programs are the most common, and some states have decades of experience with them. States that have approved DSM performance incentives as well as decoupling or LRAMs are shown in Figures 3a and 3b.

Under existing PIMs, utilities are often rewarded for the estimated load reductions they achieve beyond a threshold level of savings. Savings targets are often expressed as a percentage of retail sales and this threshold is sometimes below the target level of load savings.

[10] Berg, W., S. Vaidyanathan, B. Jennings, E. Cooper, C. Perry, M. DiMascio, and J. Singletary. 2020. The 2020 State Energy Efficiency Scorecard. Washington, DC: ACEEE. aceee.org/research-report/u2011.

[11] *Ibid.*, p. 50-51.

[12] Management fees reward the utility for spending on specific programs often by providing them a share of the expenditure. See Section 5 for further discussion of this general approach to PBR.

Figure 3a

Targeted Incentives for Electric DSM[13]

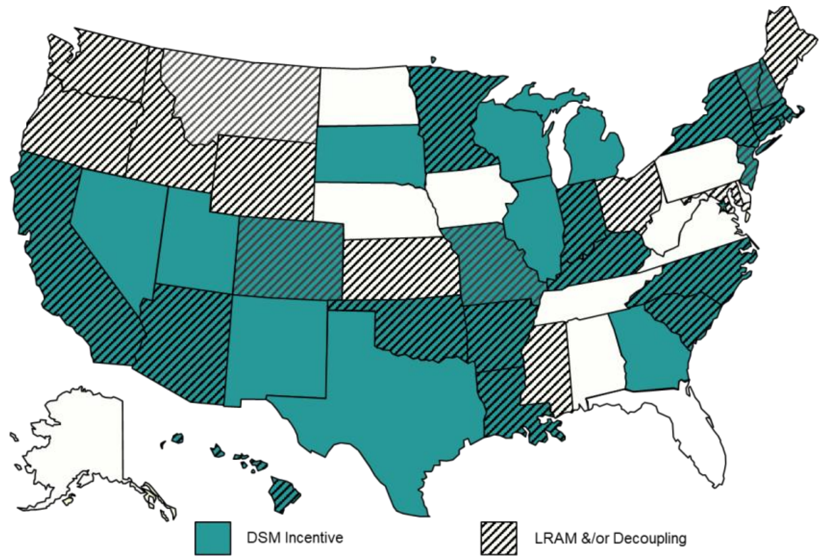
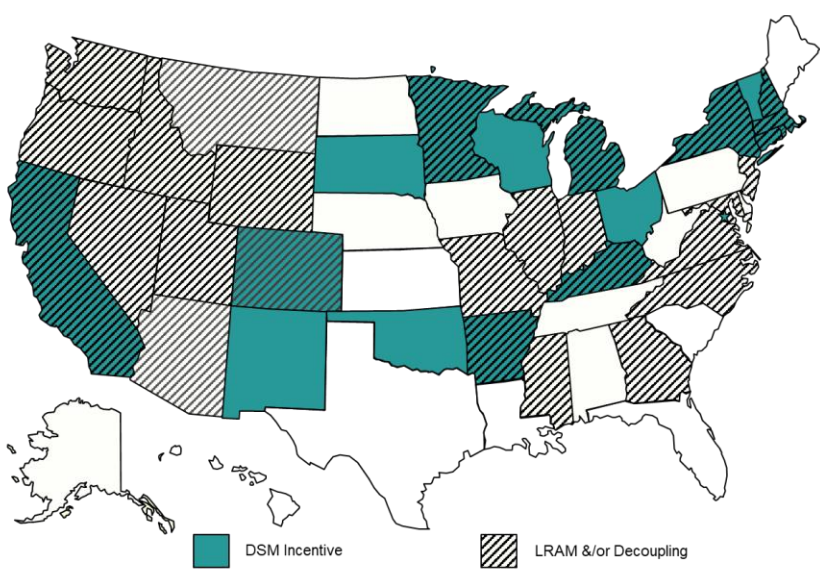


Figure 3b

Targeted Incentives for Gas DSM[14]



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[13] American Council for an Energy-Efficient Economy, *The 2020 State Energy Efficiency Scorecard*, December 2020.

[14] *Ibid*.

4.4 Metric System Advantages

Performance metric systems have notable advantages as additions to utility regulation.

- PIMs can strengthen financial incentives to perform better in targeted areas that matter to regulators, customers, and the general public. Even in the absence of explicit financial incentives, utilities have some incentive to perform well in areas where there are metrics because they can garner valuable goodwill from regulators and the public.
- Metrics and PIMs have been found particularly useful in addressing weak spots in regulatory system incentives. Many observers believe that a salient weak spot in most traditional ratemaking systems is incentives to contain environmental damage from their operations. This has kindled interest from environmental groups in PIMs that encourage less damage.[15]
- PIMs can help align utility regulation with public policy goals. Incentive weak spots can exist even in regulatory systems that contain other PBR mechanisms. One reason is that other PBR mechanisms can create undesirable incentive "side effects" that metrics and PIMs can address.
- Metrics and PIMs are also useful for alerting utilities to key concerns of regulators and stakeholders. These concerns include areas of chronically poor performance and areas of emerging performance issues.
- Metric systems can evolve incrementally and gradually as new performance concerns arise and older concerns recede.
- PIMs can streamline prudence oversight. For example, reliability PIMs can reduce the need to spend time on formal reviews of reliability.
- PIMs can be helpful in a wide variety of regulatory systems. For example, they are usually needed in MYRPs and can also be useful in jurisdictions where regulators are not inclined to implement MYRPs.
- Other means of strengthening incentives and/or reducing regulatory cost are sometimes less feasible. For example, incentivizing energy cost trackers for commodity costs through a mechanistic partial passthrough can be problematic because these costs are volatile and in great measure beyond the utility's control. A PIM for energy efficiency programs is an alternative way to incentivize reductions in fossil fuel usage which entails less risk.

[15] See for example, Cara Goldenberg, Dan Cross-Call, Sherri Billimoria, and Oliver Tully, PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals, Rocky Mountain Institute, 2020, https://rmi.org/insight/pims-for-progress/.

4.5 Metric and PIM Design Challenges

The development of an effective performance metric system for a utility is challenging. Performance is often difficult to measure accurately, for several reasons.

- The outputs from some utility activities are hard to quantify. An example is utility efforts to encourage development of markets for DSM products and services.
- Some performance metrics (e.g., reliability, delivery volumes, and peak loads) are sensitive to external business conditions, and these conditions are sometimes volatile. The utility is not then fully responsible for metric values.
- Targets that provide a realistic stretch goal for the utility and properly reflect circumstances that it can't control can be difficult to establish. For example, the SAIFI of a utility depends on the extent of system undergrounding, forestation, and the prevalence of severe storms. Improved reliability can be costly. The full set of business conditions that "drive" a metric and their relative importance is often unclear.
- Standardized data on metrics and business conditions that affect them are often unavailable for numerous utilities. The impact of external business conditions on performance metrics may be unclear and/or complicated. These problems can make it difficult to base performance targets for many metrics on operating data from other utilities.

It can also be difficult to correctly *value* performance and establish appropriate award/penalty rates for PIMs. The value of changes in performance (e.g., improved service quality and reductions in carbon emissions) is sometimes unclear. Even if it were known, the share of benefits that utilities should receive may be unclear. Customer interests are disserved if awards exceed those needed to incentivize good behavior.[16] An ideal PIM may have a nonlinear form, so that award rates rise or fall with measured performance.

Here are some other challenges encountered in developing PIMs.

- Utilities tend to resist PIMs with penalties and to propose lenient targets, while consumer groups tend to resist PIMs with rewards and propose aggressive targets.
- Regulators may have difficulty committing long term to a PIM.
- "Ratcheting" targets over time to reflect a utility's improving performance can weaken incentives.
- When there are multiple PIMs, the incentives they generate may overlap. Assigning proper weights to individual PIMs can be difficult.

These challenges in PIM development have consequences.

[16] However, customers will still benefit from PIMs provided that rewards do not exceed the benefits of actions that they encourage.

- The design and operation of PIMs can involve complicated and controversial calculations the production and review of which can erode the modest benefits of the PIMs. For example, controversy has sometimes arisen over the load impact of DSM programs that are addressed by PIMs.[17] Awards and penalties have sometimes been disputed when metrics have been influenced by external business conditions.
- The incremental regulatory cost of adding several metrics and PIMs to a regulatory system can be non-negligible. A performance metric system can in principle grow so large and complex as to constitute an undue administrative burden.
- PIMs can increase utility risk without an appropriate rate of return adjustment.
- Targets, penalties, and rewards may be too high or too low.
- PIMs may focus on more quantifiable performance dimensions and neglect dimensions that are less quantifiable but nonetheless worthwhile. For example, the DSM PIMs may focus on utility programs rather than market transformation initiatives. Amongst possible DSM programs, utilities may focus on initiatives where savings are easier to measure. For example, they might prefer direct load control (i.e., dispatchable) programs to time of use pricing.
- A focus on *summary* metrics can encourage utilities to focus too much on what's easy while neglecting more difficult initiatives that are also desirable. For example, they may focus on achieving good reliability on urban circuits and neglect rural circuits that serve few customers.

4.6 Performance Metric Systems in Practice

Approved performance metric systems reflect these considerations.

- Consideration of conditions that influence the *level* of a metric are sidestepped by making the *trend* in its value the focus of the performance appraisal. A PIM could, for example, focus on the change in a utility's SAIFI from its recent average historical value, and not address whether historical reliability was appropriate. A focus on trends is especially convenient when there is not much reason for the target to change over time.
- PIMs tend to be limited to situations where incentives are unusually weak and performance really matters.
- The need for PIMs tends to be greater to the extent that the regulatory system otherwise has weak incentive power. For example, the need for energy efficiency PIMs is greater in the absence of revenue decoupling.

[17] Gold, R., Penalties in Utility Incentive Mechanisms: A Necessary 'Stick' to Encourage Utility Energy Efficiency? *The Electricity Journal*, November 2014, p. 89.

- PIMs tend to be used where they are relatively easy to develop and administer.
- Some metrics in a performance metric system will have targets but no PIMs. Some metrics will have neither targets nor PIMs.
- Complex calculations are often eschewed in PIM design. For example, the award and penalty rates of service quality PIMs rarely reflect sophisticated calculations of the costs or benefits of changes in quality. California's Public Utilities Commission abandoned the complicated shared savings approach to the calculation of awards for DSM programs. Utilities instead receive a share of DSM expenses as a management fee.
- Some PIMs have dead bands or permit adjustments for the impact of volatile external business conditions. For example, many reliability metrics exclude major event days because these days are typically the result of unusually severe weather or other extraordinary events.
- Awards and penalties are often small, and awards may be arbitrarily capped.

4.7 New Uses for Metrics

Interest in using performance metrics in utility ratemaking has been growing in the U.S., spurred in part by the elaborate performance metric system in Britain's "RIIO" approach to energy utility ratemaking. The term RIIO stands for Revenue = Incentives + Innovation + Outputs. Metrics are used to measure outputs. RIIO includes numerous PIMs and many additional metrics. Some of the metrics and PIMs are innovative.

Performance metric systems are evolving to meet new industry challenges. Metrics that address special concerns of policymakers are sometimes called policy metrics. These metrics are sometimes used to construct PIMs. The new policy PIMs often feature awards for good performance and are often reward-only.

Load Shaping

There is growing interest in metrics and PIMs that encourage load shaping programs. The need to shape electric utility loads is growing with the increased reliance on intermittent renewable resources. Electrification of transportation and space heating can strain system capacity but can respond well to load-shaping initiatives. In the United States, reduction of systemwide peaks can also reduce the share of regional transmission costs that are assigned to a utility.

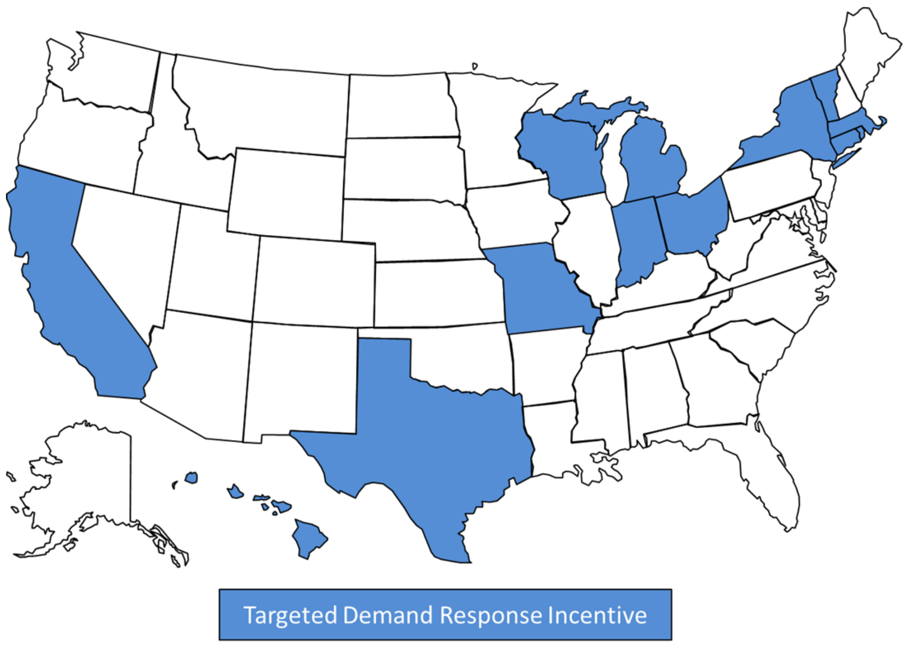
At least 13 U.S. jurisdictions have PIMs or other targeted incentives to reduce system peak demand. These jurisdictions are portrayed in Figure 4 below. Incentives are, variously, based on:

- sharing of estimated net benefits;
- return on program expenses;
- compensation for foregone earnings on avoided investments; and

- pre-established dollar amount or management fee.

Figure 4

Targeted Incentives for Electric Peak Load Management[18]



The reward is typically contingent on meeting or exceeding a threshold level of demand reduction. These PIMs sometimes incorporate capacity savings from EE programs or are complemented by energy efficiency PIMs.

AMI

In a period when many utilities are investing in AMI and other smart grid facilities, policymakers want to know if these facilities work well and are well-utilized. Potential AMI benefits include increased customer participation in load shaping programs (e.g., time-of-use ("TOU") pricing) and miscellaneous energy services that third parties offer which make use of AMI. AMI benefits also include reductions in outage duration, consumption on inactive meters, unaccounted-for energy use, and meter reading costs.

AMI metrics are monitored in several jurisdictions. These metrics have addressed several dimensions of AMI performance, including AMI functionality, utility cost savings, customer engagement, and environmental and load-management benefits. In Illinois, for example, Commonwealth Edison has

[18] Gold, R., Myers, A., O'Boyle, M., and Relf, G. (2020), "Performance Incentive Mechanisms for Strategic Demand Reduction", p. 10.

PIMs that appraise the reductions in the number of estimated bills, energy consumption on inactive meters, unaccounted for energy, and uncollectible bill expenses.

Environmental Impact

We have already noted the concern of many industry observers that utilities have inadequate incentives to contain their impact on the environment. Metrics can track utility activities that damage the environment. These metrics include GHG emissions from utility generation and vehicles, natural gas line losses, and sodium hexafluoride emissions.

Beneficial Electrification

Electric utilities can improve the environment when power generated from relatively clean resources displaces combustion of petroleum products in transportation and various other kinds of equipment. Under COSR, utilities have some incentives to promote such beneficial electrification. Between rate cases, electrification can sometimes boost capacity utilization and thereby create margins. Mobile phone providers have similar incentives to sign customers to service plans and these carriers have a high profile in American advertising. In the longer run, electrification can also bolster the need for utility grid investments that enhance earnings.

As described below, utilities nonetheless do not always have strong incentives to aggressively promote beneficial electrification.

- Revenue decoupling promptly passes any margins from electrification to customers. The problem is exacerbated by the fact that decoupling tends to be popular where EVs are popular (e.g., California and New York).
- Utilities incur costs when EV charging on customer premises increases. These costs may include those for chargers and other infrastructure upgrades which are sometimes collectively referred to as electric vehicle supply equipment ("EVSE"). The costs of EV load growth can also include those for marketing, load management, and customer support. Marketing costs may include discounts on EVSE. The cost and hassles of encouraging and then providing service to an additional EV are higher for the medium and heavy-duty vehicles that account for a disproportionately large share of hazardous transportation pollutants.
- EVs must sometimes be charged outside of customers' premises at commercial charging stations. The cost to design, permit, site, construct, own, operate, and maintain these stations may not be covered by the resultant revenue. Unprofitable charging stations will be a particular problem in the next few years while the number of EVs on the road is ramping up, but potential customers seek assurance that sufficient charging capacity will be available. The utility may get stuck with some of the less profitable locations. Even if some of the cost shortfalls were built into rates paid by other customers, that portion would once

again be fixed with respect to EV customer growth. Money can once again be saved by spending less than the budget.

- In the presence of revenue decoupling, and absent the tracking of costs of EV service, there is a disconnect between growth in the cost of service to EV customers and the growth in the funding for same. The addition of an EV load may then impose a marginal delivery cost on the utility without corresponding marginal revenue. Even if the expected cost of EV load growth is built into the revenue requirement, there is no flexible funding if EV loads grow more rapidly than anticipated. The combination of these factors can materially weaken the utility's incentive to promote EVs despite their ability to improve the environment and lower utility rates.
- The inclination of a utility not to encourage EV growth will be stronger the greater are its cost-containment incentives. One way to mitigate this problem is to track the cost of EVs for prompt or deferred recovery. Another is to exempt EV loads from revenue decoupling, where this can be easily implemented. The new law encouraging multiyear rate plans and other kinds of PBR in North Carolina requires that utility PBR proposals include residential revenue decoupling with the following exception:

> The electric public utility may exclude rate schedules or riders for electric vehicle charging, including EV charging during off-peak periods on time-of-use rates, from the decoupling mechanism to preserve the electric public utility's incentive to encourage electric vehicle adoption.[19]

Precedents

EV PIMs have been approved in New York for all of the major electric utilities that encourage electric vehicles and other kinds of beneficial electrification. These PIMs have generally been rewards-only and the primary metric has been the avoided CO2 emissions due to new electric vehicle registrations.[20] These precedents are noteworthy since electric utilities in New York operate under revenue decoupling.

Disadvantaged Customers

There is mounting concern by policymakers in some states for utility regulation to tilt more in favor of disadvantaged groups in the service territory. These groups include those with low income, poor health, and/or disproportionate exposure to unhealthy conditions created by the production and consumption of energy. Under various systems of regulation, utilities have no particular incentive to aid these groups.

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[19] North Carolina House Bill 951 Part II Section 4 (a) (c) (2), 2021.

[20] Assumptions are made about the lifetime of the vehicle and the avoided CO2 emissions per year for one or more kinds of electric vehicles.

A number of metrics are therefore in use that gauge the impact of utility operations on the welfare of disadvantaged groups. These metrics include measures of service affordability and the scale of special programs for these customers.

5. Targeted Incentives for Underused Practices

Underused practices is the term we use for desirable business practices that utilities tend to underuse. Examples include practices that reduce capex or costs that utilities have weak motivations to contain. Practices may also be disfavored because they are unusually risky. An example would be the use of equipment embodying a promising new technology which is costly or not fully proven.

Utilities can be encouraged to make greater use of underused practices by various means that include the following:

- tracking their cost for prompt recovery or deferred recovery with interest;
- capitalizing their cost (if they are O&M inputs) so that utilities can earn a return on the expenditures;
- adding a return on equity ("ROE") premium to the capitalized revenue requirement;
- paying the utility a "management fee" to use the inputs (one example is a payment equal to a share of the expenditures on the inputs);[21] and
- providing ex ante approval for innovative practices through such means as pilot programs.

These approaches have the advantage of being easy to target on weak spots in a utility's regulatory system. As such, targeted incentives for underused practices are similar to PIMs.

It is, of course, possible for incentives for underused practices to result in their *overuse*. Tactics to discourage overuse include careful prudence oversight.

5.1 Salient Precedents

Costs of several utility practices have been tracked based in part on the assumption that utilities tend to use less of them than is desirable. For example, tracking utility DSM program costs is commonplace, and these expenses have been capitalized in several jurisdictions (e.g., British Columbia). Here are additional practices that could merit encouragement based on the same reasoning:

- maintenance and refurbishment expenses that delay capex;
- support for the electrification of motor vehicles and other petroleum-fueled equipment;
- accommodation of DGS on the customer side of the meter;
- purchases of DSM services from third parties; and
- utility capex for new technologies, (e.g., AMI and storage equipment) which might lower capex on balance.

[21] ROE premia and expenditure share awards may be linked to performance metrics and targets.

Regulators in many U.S. states have approved pilot programs and/or cost trackers for innovative activities. These include capital cost trackers and/or pilots for AMI in Massachusetts, Oklahoma, and New Jersey and a compressed natural gas pilot program in New Jersey. Pilot programs are also a feature of Ofgem's RIIO approach to regulation in Britain.

Ofgem also uses a total expenditure ("totex") approach to the determination of annual revenue requirements in which a common percentage of capex and certain kinds of O&M expenses are capitalized instead of the COSR approach of capitalizing all capex and a small percentage of O&M expenses that are related to overheads. Capitalized totex is then added to the rate base. This accounting approach encourages the use of O&M inputs that may substitute for capex.

6. Multiyear Rate Plans

Multiyear rate plans are complex regulatory systems with essential characteristics and numerous optional provisions. We provide an overview of MYRPs in the first section before discussing precedents, MYRP design issues, and MYRP pros and cons in the sections that follow.

6.1 The Basic Idea

MYRPs have the following essential characteristics.

- A moratorium is placed on general rate cases. Rate cases are typically held every three to five years, but plan terms of eight and ten years have been approved.
- There is usually a need for utility revenue to grow between rate cases, as we discussed in the revenue decoupling section. In an MYRP, a RAM permits rates or revenue to grow in the face of such pressures without closely tracking all of the costs that the utility actually incurs. This externalization of revenue escalation can be accomplished in various ways, as we discuss further below.
- Costs which are difficult to address with a RAM may instead be addressed using trackers and associated rate riders or deferrals. Costs scheduled *in advance* for tracker treatment are sometimes said to be Y factored. Y-factored costs typically include those for energy commodities and frequently also include pension and benefit expenses.
- Revenue adjustments are typically also permitted for hard-to-foresee events that are largely beyond utility control and materially affect utility finances. These events are sometimes said to be Z factored.
- A performance metric system often contains PIMs that link revenue to the utility's service quality.

A number of other provisions are sometimes added to MYRPs. These include the following:

- Revenue decoupling can reduce the sensitivity of earnings to DERs, encourage innovative rate designs, and reduce concerns about the accuracy of demand projections that have been used in setting rates.
- Many plans have additional performance metrics and PIMs.
- Some plans feature earnings sharing mechanisms ("ESM") that share surplus or deficit earnings (or both) with customers when the utility's rate of return on equity ("ROE") varies from the commission-authorized target.
- Off-ramp mechanisms may permit reconsideration and possible suspension of a plan under pre-specified outcomes such as large variances between actual and approved ROEs.
- Special incentives for underused practices are common in MYRPs. For example, costs of some underused inputs may be tracked and/or capitalized.

- Some plans have marketing/pricing flexibility provisions. These typically involve light regulation of optional rates and services. Provisions like these can help utilities respond to the complex and changing needs of customers and encourage beneficial loads.
- To reduce regulatory cost and bolster incentives to achieve lasting efficiency gains, any updates to rates after the expiration of a plan may not be based entirely on a full traditional general rate case. If a rate case does occur, an efficiency carryover mechanism ("ECM") can permit the utility to keep a share of any lasting cost savings that are reflected in the new revenue requirement.

In practice, the revenue from an energy utility MYRP typically doesn't vary too far from the utility's cost for an extended period. Utilities aren't the only party to regulation that seeks to preserve some cost basis for MYRP rates. For example, consumer groups are customarily wary of letting a utility's revenue rise substantially above its cost for lengthy periods.

6.2 MYRP Precedents

MYRPs have been used in North America since the 1980s. They first applied on a large scale here to railroads and incumbent telecommunications exchange carriers. Companies in these industries faced significant competitive challenges and complex, changing customer needs that complicated COSR. MYRPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn superior returns for superior performance. In the United States, both industries achieved rapid productivity growth under MYRPs. Some states still use MYRPs to regulate incumbent local exchange carriers. The Federal Energy Regulation Commission has used MYRPs for many years to regulate oil pipelines.[22]

MYRPs have also been used on many occasions to regulate retail services of gas and electric utilities.[23] In the United States, California has used these plans since the 1980s, and MYRPs became popular in some northeastern states (e.g., Maine, Massachusetts, and New York) in the 1990s. In addition to MYRPs, several states approved extended rate freezes for electric utilities during their transition to retail competition. Rate freezes have also been part of the ratemaking treatment for some utility mergers and acquisitions.

Figure 5a shows American states that have recently used MYRPs to regulate retail gas and electric services.[24] It can be seen that these plans are now a fairly common alternative to COSR. Energy distributors operate under MYRPs in California, Ohio, New York, and New England. MYRPs also apply to

[22] See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December 2015.

[23] MYRP precedents for gas and electric utilities have been monitored by the Edison Electric Institute in a series of surveys. See, for example, Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

[24] These maps reflect the status of North American MYRPs ca July 2021.

VIEUs in diverse states that include Florida, Georgia, Louisiana, Vermont, and Virginia. In addition to Washington, a new law authorizes MYRPs in North Carolina.

Figure 5b shows that MYRPs are even more widely used to regulate Canadian energy utilities. British Columbia was an early innovator. MYRPs are also common in Alberta, Ontario, and Québec. Overseas, MYRPs are the norm in many English-speaking countries (e.g., Australia, Ireland, New Zealand, and the United Kingdom). Great Britain's RIIO approach to regulation involves MYRPs and has drawn considerable interest in the States. Countries in continental Europe which have used MYRPs to regulate energy utilities include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden. MYRPs are also common in Latin America.

Figure 5a

Recent MYRPs for Energy Utilities in American States*

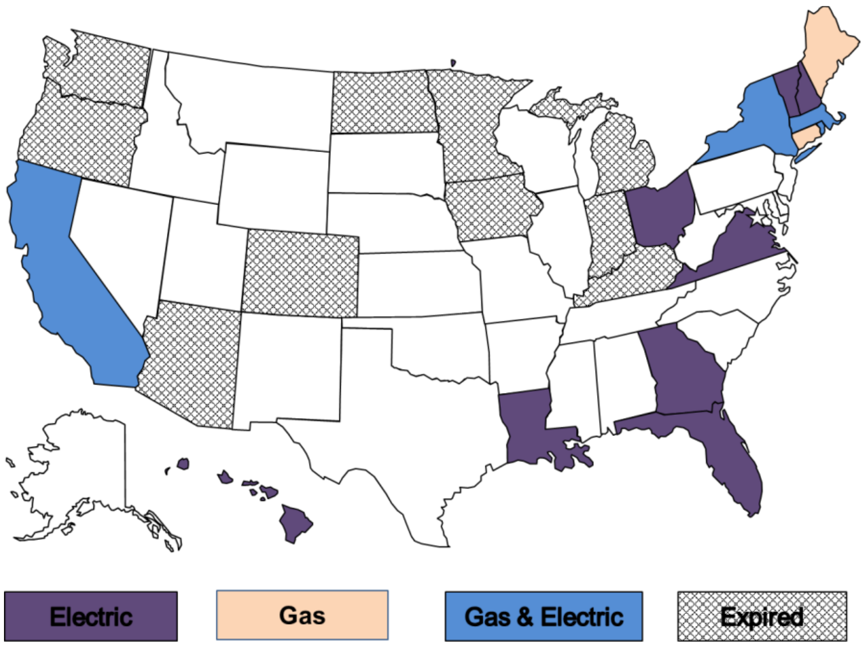
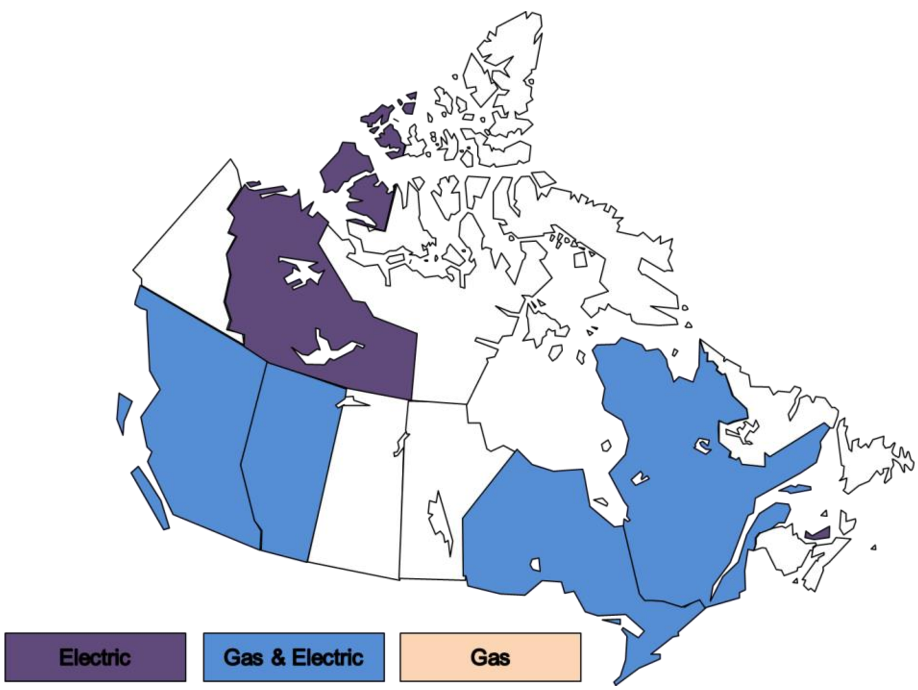


Figure 5b

Recent MYRPs for Energy Utilities in Canadian Provinces



6.3 Revenue Adjustment Mechanisms

The RAM is one of the most important components of an MYRP. As we have noted, these mechanisms can substitute for rate cases and cost trackers as a means to adjust rates for trends in input prices, demand, and other external business conditions that affect utility earnings. Utilities can bolster earnings with better performance, and this strengthens performance incentives. In this section we discuss salient issues in RAM design. We first consider how RAMs are used to cap the growth in rates and revenue. Major approaches to the design of these mechanisms are then discussed.

Rate Caps vs. Revenue Caps

RAMs can control the escalation of rates or allowed revenue. Limits on rate growth are sometimes called "price caps" whereas limits on growth in allowed revenue are called "revenue caps."

Price caps have been widely used to regulate industries, such as telecommunications, where it is desirable for utilities to market their services aggressively and promote system use. Growth in system use is generally desirable to the extent that utilities have excess capacity and use of their systems does not involve large negative externalities. When rates have high usage charges, price caps make utility earnings more sensitive to the kWh and kW of system use and thereby strengthen utility incentives to encourage greater use.

Under *revenue* caps, the escalator permits growth in allowed revenue (aka the revenue requirement). The allowed revenue yielded by a revenue cap escalator must be converted into rates, and this conversion requires assumptions regarding billing determinants. Rate growth typically does not equal allowed revenue growth since the growth rates of allowed revenue and billing determinants differ. If, for example, allowed revenue is growing by 4% but billing determinants are growing by 1%, rates will increase by 3%. Revenue caps are often paired with a revenue decoupling mechanism that reduces utility disincentives to embrace DER. In the balance of this paper we will often assume for expositional simplicity that growth in allowed *revenue* (rather than *rates*) is capped.

Approaches to RAM Design

There are several well-established approaches to RAM design. Most can be used, with modifications, to escalate rates or revenues. We discuss each in turn.

Forecasted RAMs

<u>The Basic Idea</u>

A forecasted RAM is based primarily on multi-year cost forecasts or proposals. In the United States, a RAM based on forecasts typically increases revenue by a certain predetermined percentage in each year of the plan (e.g., 4% in 2021, 5% in 2022, and 3% in 2023). Forecasted RAMs are therefore sometimes called "stairstep" RAMs.

Forecasts can be conditional on an inflation assumption and subject to a true-up when the actual inflation rate becomes known. For example, capital revenue growth can be adjusted for actual inflation in a construction cost index. In Britain, utility cost forecasts have been converted to Inflation – X formulas with equivalent expected growth.

One advantage of forecasting is that familiar accounting methods can be used when forecasting growth in capital cost. The trend in the cost of older capital is relatively easy to forecast since it depends chiefly on mechanistic depreciation. The more controversial issue, and a major focus of a typical proceeding to approve a forecasted RAM, is the value of gross plant additions during the plan term. We will call these additions "capex" for short in the balance of our discussion.

Shortcuts are sometimes taken in the design of a forecasted RAM. For example, forecasted capex may be set for each plan year at its average in recent years, or at its value for the test year of the rate case preceding the plan term. These budgets may be adjusted for inflation. The forecast of O&M expenses may be based on a formula that takes inflation into account, and possibly also trends in productivity and/or growth in the utility's operating scale.

Apart from such inflation adjustments, and any earnings sharing mechanism that the plan may include, there is often no adjustment to rates during the plan if the actual cost incurred differs from the forecast. However, some plans (e.g., some Minnesota and New York plans) return all or a portion of any capital cost savings during the plan to customers.[25] This procedure is often referred to as a "claw back." Claw back mechanisms may vary in many ways including the basis for comparison (e.g., plant additions, capital revenue requirement, or capital expenditures), the share of underspends returned to customers, the frequency of refund issuance (e.g., each year or once for the entire plan term), the flexibility afforded to the utility on the projects undertaken, and the potential to recover overspends for specific projects.

Precedents for Forecasted RAMs

Forecasts are the most common basis for RAM design in MYRPs of American energy utilities. They are, for example, currently used by electric utilities in California and New York. Some gas distributors in New York operate under revenue *per customer* caps that are based on cost forecasts. Ofgem's use of forecasts in RAM design is sometimes called the "building block" approach since the revenue requirement is built up from forecasts of component costs.

The current claw back mechanisms in the gas and electric MYRPs of Consolidated Edison ("Con Ed") refund to customers the capital revenue requirement associated with all cumulative plant addition underspends during the MYRP term. True up calculations are made for each year, but refunds are not required unless there is a cumulative underspend at the end of the plan term. There are symmetrical true ups of a limited number of projects that are required by government agencies and subject to caps on recovery of overspends to the extent that these projects cause the company's total plant additions to exceed the approved amounts. Con Ed retains flexibility to change the list of projects to be undertaken,

[25] See, for example, the MYRPs approved in New York PSC Cases 19-E-0065 and 19-G-0066.

change the priority of various projects, or their scope. In Great Britain where the revenue requirement is based on totex, totex variances are shared mechanistically between utilities and customers.

Indexed RAMs

The Basic Idea

The indexing approach to RAM design is based primarily on industry cost trend research. In research of this kind, trends in the cost of utilities are usually decomposed into trends in their input prices, productivity, and output using indexes. The decomposed cost trends can often provide the basis for just and reasonable adjustments to rates or revenue between rate cases.

The following result from cost theory is useful in the design of indexed RAMs:

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Scale} - \textit{growth Productivity}. \qquad [1]$$

The growth (rate) of a utility's cost is the sum of the growth in its input prices and operating scale less the growth in its productivity. Equation [1] provides the basis for the following revenue cap index.

$$\textit{growth Revenue} = \textit{Inflation} + \textit{growth Scale} - (X + \textit{Stretch}) + Y + Z. \qquad [2]$$

Here *X*, the "X-Factor," typically reflects the historical productivity trend of a group of utilities. Growth in allowed revenue therefore embodies an external productivity growth standard. A stretch factor (aka customer or consumer dividend) is often added to X to guarantee customers a share of the benefit of the stronger performance incentives that are expected under the plan.

In energy distribution, the number of customers served has been found to be a sensible stand-alone measure of growth in operating scale. This provides the foundation for the following revenue cap index,

$$\textit{growth Revenue} = \textit{Inflation} - X + \textit{growth Customers} + Y + Z. \qquad [3]$$

When the scale of the utility business is multidimensional, growth in its scale can be measured by a scale *index*. For example, a scale index for a VIEU could track trends in generation capacity and transmission line length as well as the number of customers that it serves.

In United States MYRPs, the inflation measure in an indexed ARM is often a macroeconomic price index such as the gross domestic product price index ("GDPPI"). This complicates the choice of an X factor since the accuracy of the GDPPI as a measure of industry input price trends becomes an issue. GDPPI growth is materially slowed by the multifactor productivity growth of the economy and typically understates growth in the prices of utility base rate inputs.

To decide on a value for X, regulators will typically want to learn about utility productivity trends by considering one or more productivity studies. Trends in the productivity of regional or broad national peer groups are commonly used to establish the base productivity trend. These studies may be sponsored by the utility, the commission, and/or intervenors. Most utility productivity research to date has focused on gas and electric power distributors.

Controversy over input price and productivity trends is common in a proceeding to approve an indexed RAM. Key issues include the appropriate sample period for trend calculations and the capital cost specifications to use in calculations. Capital cost specifications typically differ from those used in traditional utility accounting. Some experts have argued that the X factor should be calculated using a study of the trend in the "economic" or "physical" productivity of utilities. Others will argue that X should be chosen with a mind to making sensible adjustments to rates or revenue between rate cases.

The sample period has become a key issue since, in some sectors of the utility industry (e.g., power transmission), productivity growth has slowed markedly in recent years, in some cases turning negative. Research is underway to ascertain the drivers of negative productivity growth. This research can shed light on circumstances in which negative productivity growth targets are reasonable. Possible drivers of negative productivity growth include a need for system modernization and improved reliability.

When RAMs are indexed, controversy may also arise over the need for supplemental capital revenue. The X factor term of the RAM formula is typically based on the long-term productivity trend of the industry. Utilities have often argued that the resultant RAM formula provides inadequate revenue growth to fund a needed capex surge. Supplemental capital funding has been granted in numerous proceedings where indexed RAMs have been approved.

Precedents for Indexed RAMs

The indexing approach to RAMs design originated in the United States.[26] Development was facilitated there by the availability of standardized, quality data for numerous companies in several utility industries. First applied in the railroad industry, indexed RAMs have subsequently been used on a large scale to regulate telecommunications utilities and oil pipelines.

California, Maine, and Massachusetts were early adopters of indexed RAMs in retail energy utility regulation. Energy utilities that have operated under such RAMs include Bay State Gas, Boston Gas, Central Maine Power, the Hawaiian Electric Companies, NSTAR Electric (MA), NSTAR Gas (MA), National Grid (MA), San Diego Gas & Electric, Southern California Edison, and Southern California Gas.

RAMs based chiefly on index research are now used more widely to regulate utilities in Canada than in the United States. The Canadian Radio-television and Telecommunications Commission was an early adopter. Indexed RAMs have also been used to regulate rail freight rates in western Canada. British Columbia and Ontario were the first Canadian provinces to use indexed RAMs in gas and electric utility rate setting. Energy distributors in Alberta, Ontario, and Québec currently operate under indexed RAMs.

[26] Early American papers discussing the use of price and productivity research to design ARMs include Baumol (1982).

Hybrid RAMs

The Basic Idea

"Hybrid" approaches to RAM design use a mix of index research and cost forecasts. A popular hybrid approach in North America involves separate treatment of the revenue (or rates) that compensate utilities for their O&M and capital costs. Indexes address O&M expenses while forecasts address capital cost. Since capital cost is forecasted, hybrid RAMs may also include clawbacks of capex underspends and adjustments for actual inflation.

Precedents for Hybrid RAMs

The hybrid approach to RAM design that is popular in North America was pioneered in California in the 1980s. This approach has been found to be adaptable to the diverse cost trajectories of California's gas and electric utilities and has been used before and since the restructuring of the electric power industry. Hybrid RAMs in California sometimes adjust the level of plant additions to reflect the latest inflation in the Handy Whitman construction cost index. A hybrid approach is currently used in the RAM of Southern California Edison and was used in the recent RAMs of the three Hawaiian Electric utilities.

The "Custom IR" approach to MYRP design that larger electric utilities use in Ontario has typically also used hybrid RAMs. Under this approach, a rate or revenue cap index applies to all base revenue but a "C factor" term in the index formula ensures that the resultant revenue for capital covers the approved growth in the capital revenue requirement. Clawbacks of capital cost savings are the norm. Hydro One Networks has claw back mechanisms in its current MYRPs which allow the company to retain 2% of cumulative plant addition underspends at the end of the plan term; it is also permitted to keep the benefit of capital underspends due to "verified productivity savings."[27]

Rate Freezes with Supplemental Capital Revenue

Some MYRPs feature a rate freeze in which the RAM provides no automatic rate escalation during the plan. Revenue growth then depends mainly on growth in billing determinants and any tracked costs. In the energy utility industry, such freezes usually apply only to base rates due to the volatility of energy costs.

Unchanged rates are compensatory for utilities when the growth in the costs addressed by these rates matches the growth in their billing determinants. Such favorable operating conditions have occurred over the years under special circumstances.

- Rate freezes have often been featured in telecom MYRPs where utilities were experiencing slow input price inflation and rapid technological change and demand growth.

[27] Ontario Energy Board EB-2017-0049 and EB-2019-0082.

- We noted in Section 2.2 that electric utilities in the first two decades of the postwar period generally experienced brisk demand growth and, except during wars, slow inflation. Some utilities were able to operate for many years without rate cases.
- Following the addition of large solid-fuel power plants to their rate base in the late 1980s and early 1990s, some VIEUs experienced unusually slow cost growth due to excess generating capacity and flat or declining generation rate bases. Inflation was moderate and growth in average use, though slower than in the 1940-1970 period, was still materially positive. Several VIEUs (e.g., Florida Power and Light) operated without general rate cases for more than a decade under these conditions.
- Mergers and acquisitions have facilitated rate freeze agreements by creating temporary but sometimes sizable cost containment opportunities as the parties realized economies of scale (and sometimes scope).

Favorable circumstances like these are less common today. Inflation is currently brisk, and we have noted that some utilities need high capex today and there is typically no growth in average use available to finance cost growth.

Precedents for Rate Freezes with Supplemental Capital Revenue

Rate freezes have nonetheless recently been approved for several U.S. electric utilities. These are typically vertically integrated utilities that are increasing their generation rate base. Provided that a few costs that are growing are tracked or accorded a forecasting treatment, they do not need any further rate escalation for several years. Quite often, the annual cost of the new plant additions is added gross of any depreciation that occurs in the value of older plant. The depreciation of older plant is then available to help fund the growth of O&M expenses. This approach to RAM design has been used by VIEUs in Arizona, Florida, Louisiana, and Virginia.

RAM Designs for Distributors and VIEUs

Distributors

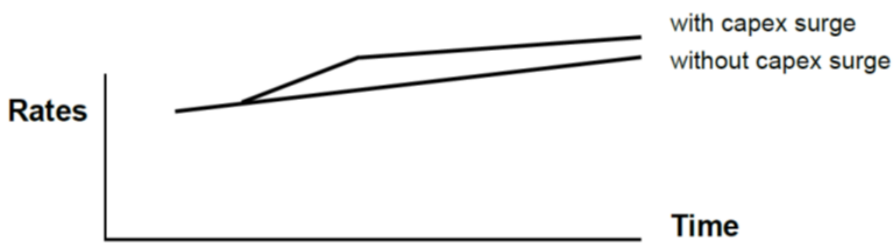
Different approaches to RAM design can make sense for energy distributors and VIEUs. Indexed RAMs have been popular in the regulation of North American gas and electric power distributors. One reason is that the cost of distributor base rate inputs often grows gradually and predictably as the economies of the service territories they serve expand. Capex is required each year to extend service to new residential subdivisions and commercial and industrial complexes. Replacement of distributor facilities approaching the end of their service lives is typically spread out over time for similar reasons.

However, some energy distributors have experienced periods of unusually high capex that accelerate cost growth. Common triggers have included the rapid build out of advanced metering infrastructure or other “smart grid” technologies; changes in reliability, resiliency, and/or safety standards of government agencies; and accelerated programs of replacement capex (“repex”). The construction or replacement of a substation may occasionally cause a surge in the capex of a small (e.g., municipal) distributor.

High repex can result from an "echo effect" as assets added in a past period of unusually rapid system growth reach replacement age. Productivity growth is especially sensitive to repex since highly depreciated assets valued in *historical* dollars are replaced with assets that are valued in *current* dollars, are designed to last for decades, and must conform to the latest performance standards (e.g., National Electric Safety Code 2017). These standards typically exceed any that were previously applicable and may incorporate new technologies. The changing revenue requirement trajectories of utility distribution companies are depicted in Figure 6a.

Figure 6a

Revenue Requirement Trajectories of UDCs



VIEUs

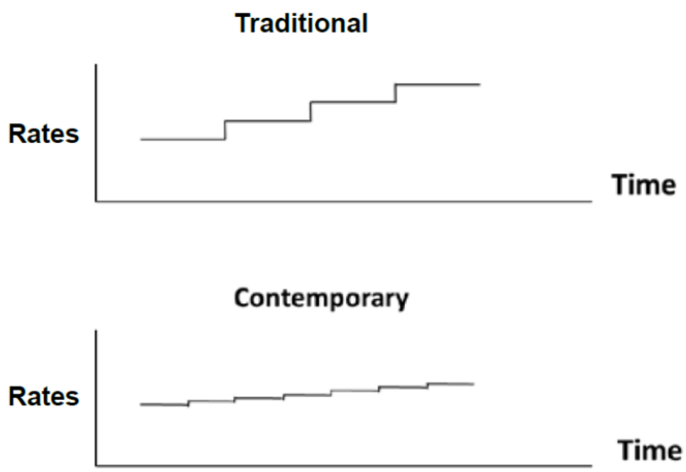
VIEUs have in the past had revenue trajectories that better resembled stair steps because big cost increases when major additions to generation plant came into service alternated with periods of slow cost growth as these additions depreciated. This pattern discouraged use of indexed RAMs. Another complication for VIEUs was that the exact timing of major plant additions was often uncertain, due in part to construction delays. The following approaches to RAM design have been used for VIEUs.

- Indexing (e.g., Hawaiian Electric)
- Forecasted (e.g., Northern States Power Minnesota)
- Hybrid (e.g., Southern California Edison)
- Freeze with supplemental capital revenue (e.g., Appalachian Power, Arizona Public Service, Florida Power & Light, Tampa Electric, and VEPCO)

Some VIEUs are today experiencing more gradual cost growth because fewer major generation capacity additions are needed (due to slower demand growth and greater reliance on power purchases). Generation capacity that is built tends to be somewhat smaller gas-fired or wind or solar-powered units. Capital cost growth may still be brisk, due in part to a need for new transmission capacity to reach clean generation capacity or for a modernization of the distribution system. The changing revenue requirement trajectories of VIEUs are depicted in Figure 6b.

Figure 6b

Revenue Requirement Trajectories of VIEUs



Z Factors

As noted in Section 6.1, a Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings and are not effectively addressed by other ARM provisions. Many MYRPs have explicit eligibility requirements for Z-factor events. Here is a typical list of requirements.

Causation: The expense must be clearly outside of the base upon which rates were derived.

Materiality: The event must have a significant impact on the finances of the utility. Materiality can be measured based on individual events or the cumulative impact of multiple events. Some plans have materiality thresholds of both kinds.

Outside of Management Control: The cost must be attributable to some event outside of management's ability to control.

Prudence: The cost must have been prudently incurred.

Eligible events may, in principle, raise or lower earnings. For example, a cut in corporate income taxes could raise earnings.

One of the primary rationales for Z-factor adjustments is the need to adjust revenue for the effect of changes in tax rates, highway relocations, mass transit construction, system undergrounding requirements, and other government initiatives on utility cost. Absent such adjustments, policymakers can adopt new policies that increase the cost of a utility, confident in the knowledge that its earnings, rather than customer bills, will be affected between rate cases.

Z-factors can reduce utility operating risk and encourage more cautious behavior by government agencies, without weakening performance incentives for the majority of costs. Z-factors can thus reduce the possibility that an MYRP needs to be reopened, while maintaining most of the benefits of MYRPs. Disadvantages of Z factors include the fact that they can materially raise regulatory cost, and the possibility that they may weaken utility incentives to mitigate the impacts of triggering events. It may be easier for the utility to obtain higher revenue from the process than it is for customers to obtain lower revenue.

6.4 Targeted Incentives for Underused Practices

MYRPs often include targeted incentives for underused practices. The need for such incentives can increase in an MYRP for some underused practices since there is more pressure on departments to contain their costs and this includes the costs of these practices. MYRPs are sometimes touted for encouraging innovation but, in practice, utilities often worry that innovative practices might be adversely treated by regulators in the next rate case.

Utility DSM expenditures are commonly tracked in North American MYRPs. We noted in Section 5.1 above that the British approach to RAM design is based on totex rather than traditional COSR. MYRPs in Australia, Britain, and the U.S. have had provisions for pilot programs.

6.5 Performance Metric Systems

Performance metric systems were noted in Section 6.1 to be a standard feature of MYRPs. Many MYRPs have service quality PIMs. A wide variety of additional metrics and PIMs have been used in MYRPs. DSM PIMs have been especially common.

6.6 Plan Termination Provisions

Plan termination provisions are one of the more important issues in MYRP design. Successor rates are often reset in a general rate case, and this typically occurs in the last year of the plan. This option passes all benefits of any long-run cost savings achieved during the plan to customers. A true up to cost is also welcomed if poor plan design had caused marked earnings surpluses or deficits.

The downsides of scheduling rate cases in advance are several and include the following.

- This option involves relatively high regulatory cost.
- Performance incentives are weakened. The incentive to realize longer-term gains is known to attenuate in the later years of an MYRP. This occurs because utilities would in those years incur the upfront costs of performance-improving initiatives but receive few (or none) of the benefits that result.

Several alternatives to scheduled rate cases have been devised that can mitigate these problems. The plan may contain no requirement that a rate case be held to set new rates. Parties may retain the option to negotiate a plan extension. New rates that are otherwise based on a traditional rate case may be subject to adjustment under the terms of an efficiency carryover mechanism.

6.7 MYRP Proceedings

A proceeding to approve an MYRP often includes a conventional rate application to establish the revenue requirement for the first plan year. One advantage of this approach is that the parties to the proceeding can consider the initial rates and rate escalation as a "package deal." However, the rate effective year following a rate case usually provides sufficient time for a proceeding to establish a multiyear plan that escalates the rates in succeeding years.

In many proceedings to establish MYRPs the utility has filed the first plan proposal. Other parties then provide commentary on the utility's proposal and counterproposals. Some proceedings are fully litigated, but many result in a negotiated settlement between the parties.

At the outset of MYRP ratemaking, or where a common approach to MYRP design is sought for multiple utilities, a generic proceeding has sometimes been convened that is independent of the rate case process. This approach affords parties the time for a more in-depth consideration of various PBR issues. Collaborative discussions have occurred in such a context.

6.8 MYRP Pros and Cons

Advantages

MYRPs have several general advantages over COSR under modern operating conditions. The RAM can provide timely rate escalation for increasing cost pressures. The frequency of rate cases can thus be reduced without tying rate adjustments too closely to the utility's own costs. This means that there are increased opportunities for utilities to bolster earnings from various efforts to contain growth in the rate base and other costs that are addressed by the RAM. There is more incentive to buy services rather than build plant when this is the low-cost strategy. The RAM thus addresses attrition at the same time that it strengthens performance incentives. Avoiding a full true up of revenue to the company's cost when the plan expires by such means as an ECM can magnify the incentive "power" of the plan considerably.

Provisions can be added to MYRPs which further strengthen a utility's incentive to embrace DERs. These provisions include revenue decoupling and the tracking of utility DSM expenses. In addition, MYRPs can, by strengthening general incentives to contain cost, provide their own incentive for utilities to use DERs to contain load-related costs of base rate inputs such as load-related capital expenditures. For example, TOU pricing has more appeal since this can help contain growth-related costs.[28] Note also that MYRPs strengthen incentives to embrace DERs without requiring complicated load or cost savings calculations. The combination of an MYRP, revenue decoupling, demand-side management PIMs, and the tracking of DSM-related costs can thus provide four "legs" for the DSM "stool."[29]

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[28] Railroads operating under MYRPs used pricing provisions aggressively to encourage less costly service requests.

[29] A *three*-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in Dan York and Martin Kushler, "The Old Model Isn't Working: Creating the Energy Utility for the 21st Century," ACEEE, September 2011.

The PIMs included in the plans can address “holes” in the incentive framework. For example, we have noted that MYRPs can strengthen incentives to contain costs, and these include costs incurred to maintain or improve service quality and safety. In competitive markets, a producer’s revenue can fall materially if the quality of its offerings falls below industry norms. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality.

MYRPs can also encourage good utility performance by increasing operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency and reliance on RAMs for revenue escalation means that the prudence of some utility costs may be considered less frequently. Utilities are more at risk from bad choices (e.g., needlessly high capex) and can gain more from good choices. Knowledge of stronger incentives informs commission reviews of a utility’s operating prudence.

To the extent that products and services aren’t subject to revenue decoupling, an MYRP can also strengthen incentives to market them effectively. This is a useful attribute in an era when changing technologies and customer needs create opportunities for new rates and services. Services to price-sensitive large-volume customers are sometimes exempted from decoupling provisions.

With stronger performance incentives and greater operating flexibility, MYRPs can encourage better utility performance. The strengthened performance incentives can encourage a more performance-oriented corporate culture at utilities. Benefits of better performance can be shared with customers via earnings sharing mechanisms, occasional rate cases, an efficiency carryover mechanism, and/or RAM design. Customers can also benefit from the more predictable rate growth that MYRPs make possible. Rate trajectories can be sculpted to diminish rate bumps.

MYRPs can also improve the efficiency of regulation. Rate cases are less frequent and can be better planned and executed. The terms of MYRPs of utilities in the same jurisdiction can be staggered so that rate cases overlap less. Streamlining the rate escalation chore can free up resources in the regulatory community to more effectively address other important issues. Senior utility executives have more time to attend to their basic business of providing quality service cost-effectively.

Disadvantages

MYRPs also have some disadvantages. They are complex regulatory systems that require skills that the regulatory communities in some jurisdictions do not possess. It can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise over plan design. The main source of controversy in a typical MYRP proceeding is the appropriate RAM.

These and other concerns have prompted many consumer advocates to oppose MYRPs. Best practices in the MYRP approach to regulation have evolved to address many of these problems. For example, utilities are increasingly expected to support cost forecasts with capital spending plans.

7. Application to Puget Sound Energy

7.1 PSE Background

Company Overview

PSE is an investor-owned energy utility that resulted from the 1997 merger of Puget Sound Power and Light and Washington Natural Gas. It is the largest provider of retail gas and electric services in Washington. Retail electric service is provided in most cities surrounding Seattle and Tacoma and in other counties in western Washington. Gas is distributed to most of the Seattle/Tacoma metro area and some surrounding areas.

PSE's electric operations are to some degree vertically integrated. More than half of its retail sales are self-generated. Roughly half of this generation is from gas-fired units. Most of the rest of PSE's generation is from wind farms in Washington state or a coal-fired plant in eastern Montana. The Company owns power transmission assets but relies extensively on the Bonneville Power Administration ("BPA") for transmission services. With a substantial reliance on generation and transmission by others, the growth of power distributor costs looms large in the total cost of the Company's base rate inputs.

Regulation

PSE's retail gas and electric services are regulated by the UTC. The Company is also subject to numerous Washington statutes.

Rate Cases and Trackers

Rates that address the cost of the Company's non-fuel O&M and capital can be adjusted in general rate cases. Some costs receive tracker/rider treatment. These include expenses for natural gas delivered to customers, gas transmission, and property taxes. The energy cost tracker for PSE's electric operations, called the Power Cost Adjustment mechanism, features a partial passthrough of differences between actual power costs and "power cost baseline" costs that are established using normalizing assumptions about weather and hydrological conditions.

Integrated System Planning

Washington electric utilities have been required by law to file integrated resource plans periodically since 2008. The Commission's rules for integrated resource planning include a requirement that an electric utility's portfolio analysis and preferred portfolio include, among other things "all cost-effective, reliable, and feasible conservation and efficiency resources, … and demand response."[30]

[30] WAC 480-100-620 (11) (c).

DSM

The Energy Independence Act requires large investor-owned electric utilities to "pursue all available (electric) conservation that is cost-effective, reliable, and feasible."[31] Conservation is defined to include high-efficiency cogeneration by retail customers. Responsibility for monitoring the prudence of conservation programs is assigned to the UTC. Utilities must pay a penalty per MWh for shortfalls from conservation goals. As part of the Clean Energy Transformation Act ("CETA"), the Washington legislature added a mandate to "pursue all cost-effective, reliable, and feasible conservation and efficiency resources, and demand response."[32]

Washington statutes also mandate DSM for gas utilities, stating:

> "Each gas company must identify and acquire all conservation measures that are available and cost-effective… The cost effectiveness analysis … must include the costs of greenhouse gas emissions."[33]

This statute mandated the adoption of a conservation target based on a gas conservation potential assessment which must be prepared by an independent third party.

The legislature has long recognized the potential need for incentives to support conservation efforts. RCW 80.28.024 states that

> The legislature finds and declares that the potential for meeting future energy needs through conservation measures, including energy conservation loans, energy audits, the use of appropriate tree plantings for energy conservation, and the use of renewable resources, such as solar energy, wind energy, wood, wood waste, municipal waste, agricultural products and wastes, hydroelectric energy, geothermal energy, and end-use waste heat, may not be realized without incentives to public and private energy utilities. The legislature therefore finds and declares that actions and incentives by state government to promote conservation and the use of renewable resources would be of great benefit to the citizens of this state by encouraging efficient energy use and a reliable supply of energy based upon renewable energy resources.

Clean Energy Policies

Washington was one of the first American states to have a renewable portfolio standard. The currently effective renewable portfolio standard target is 15% of average load from the prior 2 years. CETA, passed in 2019, contains the following additional provisions.

- The Company cannot charge retail customers for costs of generation from its coal-fired power plant after 2025.

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[31] RCW 19.285.040 (1).

[32] RCW 19.405.040, (6)(a).

[33] RCW 80.28.380.

- Retail electric sales must be GHG neutral by 2030 via a combination of renewable generation, other non-emitting generation, and/or alternative compliance options.
- 100% of electricity must be obtained from renewable or non-emitting sources by 2045.
- Benefits of the energy transition must be broadly shared. To this end, utilities must routinely report information on the energy burden of and energy programs for disadvantaged customers.
- Utilities must file clean energy implementation plans ("CEIPs") every 4 years starting in 2021.

Transportation Electrification

The Washington Department of Ecology recently approved rules to implement California's vehicle emission standards beginning in model year 2025.[34] PEG's understanding is that this would require 8% of new light and medium-duty vehicle sales in Washington be zero emission vehicles beginning in model year 2025.[35]

The state of Washington is establishing a Clean Fuels Program with a Low Carbon Fuel Standard that is similar to those in California and Oregon.[36] The proposed standard provides for a decline in the carbon intensity of Washington transportation "fuels" (which include electricity) in accordance with the following schedule.

- 0% in 2022
- 0.5% reduction in 2023
- 0.5% incremental reduction in 2024
- 1% max incremental reduction in 2025
- 1% max incremental reduction in 2026
- 1% max incremental reduction in 2027
- 1.5% max incremental reduction in 2028
- 1.5% max incremental reduction in 2029

The compliance obligations of fuel suppliers whose fuels have a carbon intensity exceeding the standard can be offset by purchasing credits from suppliers of cleaner fuels and fueling capacity. While the rulemaking on these matters is not complete, it is anticipated that electric utilities will receive marketable credits for at least residential electric vehicle charging. Premium credits may be available

[34] HB 1287 – 2021, Preparing for a zero-emission transportation future.
[35] Zero emission vehicles also include hydrogen fuel cell vehicles.
[36] HB 1091 - 2021, Reducing greenhouse gas emissions by reducing the carbon intensity of transportation fuel.

for "smart vehicle charging technology" that facilitates more charging when renewable energy supplies are abundant.

Utilities are supposed to spend most or all of their credit revenue to promote further transportation electrification ("TE"). Eligible expenditures include those for "expanding grid capacity to enable TE investments." Some of the money will be targeted for programs that benefit low income and frontline communities.

PBR

The Company's regulatory system already contains several PBR provisions.

Revenue Decoupling

Revenue decoupling was first approved by the UTC for Puget Sound Power & Light in 1991 but its use later lapsed. Decoupling resumed for PSE in 2013 and has continued to be part of the Company's regulation. It currently applies to all electric customers except high-demand commercial, industrial, and lighting customers and to all gas customers except for gas lighting and commercial and industrial customers taking service under specific rates. Between rate cases, allowed revenue for gas and electricity delivery and general costs is currently escalated automatically for customer growth but fixed costs of power generation are not.

Service Quality Metrics and PIMs

PSE has had a Service Quality Program since the 1997 merger. The ratemaking provisions of this program have three components:

- Penalty-only PIMs based on 9 Service Quality Indexes ("SQIs") encompassing electric reliability; electric and gas safety; and gas and electric customer service;[37]
- Customer Service Guarantees and bill credits for poor service; and
- Restoration Service Guarantees and bill credits for poor service.

Results are reported for several additional SQ measures. A Service Quality and Electric Service Reliability Report is submitted to the WUTC annually.

Other Metrics

PSE reports metrics to the Commission and stakeholders in various performance areas but has no additional PIMs. For example, the Company provides progress reports to the Joint Utility Transportation Electrification Stakeholder Group which include several metrics on transportation electrification.

[37] The SQI for SAIDI is not tied to a penalty.

Targeted Incentives for Underused Practices

Recovery of the Company's DSM expenses is facilitated by the Electric Conservation Rider and the Natural Gas Conservation Rider. The UTC has approved several pilot programs for PSE. Here are some examples.

- An electric conservation incentive pilot was approved for PSE in 2006. The program was reviewed by a 3rd party.
- A pilot was approved for the Glacier Battery Storage Project.
- A pilot program has explored the use of load management for electric vehicle customers.

MYRPs

An MYRP with a "stairstep" RAM was approved for PSE at the time of the merger.[38] Four electric and gas rate cases were then held between 2006 and 2011.[39] Underearning was chronic.

In 2013, the Commission approved new MYRPs (called a "rate plan") for the Company's gas and electric services. These plans had the following provisions:

- Fixed, constant annual escalation factors (called K factors) for non-energy revenue per customer were established;
- 3% soft cap on growth in the rates for decoupled services;
- Revenue decoupling without an ROE reduction;
- 50/50 sharing of all surplus earnings; and
- A 3-4 year term.

In approving these plans, the Commission emphasized the high regulatory cost of frequent rate cases.

Since the conclusion of the second MYRP in 2017, PSE filed rate cases in 2017 and 2019 and an expedited rate filing in 2018. Mindful of the pandemic and its economic impact, the Commission granted little rate relief in the 2019/2020 proceeding and rejected a proposal for an attrition adjustment. This decision increases the need for rate relief in this proceeding.

Ratemaking Treatment of New Assets in Rate Effective Years

In Docket U-190531 the UTC established a policy concerning the ratemaking treatment of utility assets that are expected to become used and useful in the rate effective year (or years) following the conclusion of a rate case. These principles apply to MYRPs. The Commission permits provisional recovery in rates of the annual cost of such rate-effective period property. However, this revenue may be reviewed and refunded to customers if the Commission later determines that the assets are not used and useful or that the cost of the assets is not known and measurable, adequately matched to offsetting

[38] WUTC Docket UE-960195.
[39] PSE also filed an expedited rate case for natural gas during this period.

factors, or prudently incurred. If identified investment costs exceed what the regulated company is collecting from customers based on its proposed, estimated, or projected costs, the Company may file an accounting petition.

Recent PBR Legislation

Senate Bill 5295, signed by Governor Inslee in 2021, encourages the Commission to use PBR for gas and electric utilities. These utilities are required to propose MYRPs in their rate cases. The bill also established MYRP guidelines that include the following.

- For each rate year of a multiyear rate plan the Commission shall ascertain and determine "the fair value for rate-making purposes of the property of any gas and electrical company that is or will be used and useful under RCW 80.04.250 for service", along with "the revenues and operating expenses for ratemaking purposes."[40]
- The Commission is accorded substantial flexibility in the approval of plan details. Subsection 2(3)(d) of the law states, for example, that

  > [i]n ascertaining and determining the fair value of property of a gas or electrical company pursuant to (b) of this subsection and projecting the revenues and operating expenses of a gas or electrical company pursuant to (c) of this subsection, the commission may use any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates.

- Plans must have a particular kind of ESM. Earnings more than 50 basis points above allowed levels shall be deferred "for refunds to customers or another determination by the commission in a subsequent adjudicative proceeding."[41]
- The Commission must determine a set of performance measures that will be used to assess a gas or electrical company operating under an MYRP.
- An MYRP may be as long as four years. A utility is bound by the terms of the plan in years one and two but may file for new terms to be effective beginning in year three or in any fourth year of a plan.
- Plans must also have a low-income assistance program that includes a discount rate for low-income customers as well as grants and other low-income assistance programs.

In addition, SB 5295 requires the UTC to conduct a proceeding to develop a policy statement on alternatives to COSR which include "performance measures or goals, targets, performance incentives, and penalty mechanisms." The Commission has proposed a schedule for this proceeding. Metrics would be addressed first, and a policy statement on metrics is to be issued in March 2023. A policy statement on PIMs is to be issued in December 2024.

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[40] SB 5295 Sec. 2 (3) (b) and (c).

[41] SB 5295 Sec. 2 (6).

The following criteria were itemized in SB 5295 for evaluating metrics and performance measures in MYRPs.

- Service reliability
- Customer satisfaction and engagement
- Timely execution of competitive procurement practices
- Attainment of state energy and emissions reduction policies
- Clean energy or renewable procurement
- Rapid integration of renewable energy resources
- Conservation acquisition
- Demand-side management expansion
- Lowest reasonable cost planning
- Affordability
- Cost of service
- Increase in energy burden
- Rate stability
- Fair compensation of utility employees

When reviewing MYRP proposals, SB 5295 also states that the Commission should consider a public interest standard that encompasses environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity. This enumeration of criteria clearly emphasizes environmental and equity considerations as well as the more traditional regulatory concerns about the cost and quality of service.

Company Operations

Sources of Energy

Roughly a third of PSE's retail power sales are currently provided from renewable and other nonemitting resources. The Company has retired several of its jointly-owned coal-fired generating units in recent years and plans to stop selling Washington retail customers power from its coal-fired generation by 2025. PSE has become one of the largest utility generators of wind power in the nation and is the largest utility producer of renewable energy in Washington. The Company has met all the renewable energy targets to date.

PSE has a target of a 30% emissions reduction from natural gas by 2030 and a goal of achieving net zero carbon emissions for natural gas sales by 2045. The Company has also been integrating renewable natural gas onto its gas system over the past 30 years and plans to increase the RNG it acquires from around 1.5% of gas sales to nearly 3.5% by 2024. PSE is exploring whether hydrogen can replace traditional forms of natural gas on its system and whether hydrogen can be produced more cleanly and economically.

PSE's Clean Energy Implementation Plan outlines several programs that the Company will undertake over the 2022-2025 period. The Company will continue its EE programs at the same levels as at present, develop and ramp-up load control programs, purchase additional renewable resources, develop distributed solar resources, undertake several local non-wires alternatives projects, deploy more storage, and implement a residential TOU rates pilot program. PSE expects that its Clean Energy Implementation Plan will nearly double the share of PSE's electric supply that is from renewable or non-emitting sources between 2020 and 2025.

Grid Modernization

PSE is proposing an extensive grid modernization program to ensure that it can implement its Clean Energy Implementation Plan and improve its reliability as measured by SAIDI and SAIFI. The Company is planning to undertake several projects to enable DERs including a virtual power plant, improved data capabilities, developing a non-wires alternative evaluation tool, and deploying an advanced distribution management system platform. PSE has adopted a shorter cycle for pole inspections; identified assets at higher risk of failure and developed replacement plans for those assets; and is developing an enhanced vegetation management program. A buildout of the AMI needed for TOU pricing is underway.

DSM

PSE has had a DSM program since 1979. There has been a big ramp up of its DSM programs since 2002. The Company has a highly regarded review and evaluation program. PSE's DSM programs have saved more than 67 billion electric kWh and 600 million natural gas therms since these programs began.

Beneficial Electrification and Green Energy

PSE customers have several options to participate in renewable energy programs administered by the Company. There is a Green Power Program for residential and commercial customers, a Green Direct program for government and large-volume customers, and a Carbon Balance Program for gas customers. The Company ranks in the top 10 nationally for green power sales, green power customers, the share of sales that are for green power, and the green power participation rate.[42] Net metering for customers with solar panels is also available, and more than 10,000 customers participate. Customers may also choose to subscribe to community solar programs.

Electrification of Transportation

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[42] National Renewable Energy Laboratory (2021), "Top Ten Utility Green Pricing Programs (2020 Data)". Accessed at: https://www.nrel.gov/analysis/assets/pdfs/green-pricing-top-10-2020-data-plus-archives.pdf.

The Company has established the following rate schedules for electrification of transportation

551 Non-Residential Charging Products and Services (e.g., workplace and public charging services);

552 Residential Charging Products and Services (single and multifamily); and

554 Electric Vehicle Low Income Transportation Service.

Low Income Assistance

PSE has had a low-income assistance program since 2002. In addition to bill subsidies for qualifying customers, PSE has a weatherization program for low-income customers. PSE is also reserving part of its community solar program for income-eligible customers to participate in at no cost.

7.2 PSE's MYRP Proposal

The Company's proposed MYRP is detailed in the Prefiled Direct Testimony of Jon A. Piliaris, Exh. JAP-1T. Here are some salient features.

- Initial rates would be established in this proceeding.
- Escalation of base revenue would then be driven for two years by the Company's latest five-year financial plan. This plan is detailed in the testimony of Mr. Joshua A. Kensok, Exh. JAK-1T. Of the various established approaches to RAM design that we discussed above, this one is most consistent with RCW 80.28.425(3) parts (b) and (c).
- As discussed in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, the portion of the Company's proposed rate increases that is tied to projections of assets that are expected to become used and useful during the plan is subject to refund after Commission review. This provision is consistent with the UTC's decision in Docket U-190531.
- Revenue would be subject to an adjustment for unforeseen inflation.
- Revenue decoupling is vitally important to encourage DSM and supportive rate designs and to reduce concern about the use of billing determinant forecasts in ratemaking. It would continue for gas and electric services to residential and most commercial and industrial customers.
- As provided for in SB 5295, any surplus earnings, defined as those which would cause the Company's rate of return on rate base ("ROR") to exceed its authorized target by more than 50 basis points, would be deferred for refunds to customers or another determination by the Commission in a subsequent proceeding.
- The various low-income provisions of the plan include a special rate for low-income customers.
- The plan contains a shortlist of performance metrics and PIMs that are particularly appropriate for tracking PSE's performance during the plan and for encouraging good

performance. Results would be posted on a publicly-available MYRP scorecard. Additional metrics on various topics will continue to be reported routinely by PSE in other venues.

- Unless the Company exercises the right to request a new plan prior to year three, the plan will have a term of three years.

7.3 Performance Metric System

In developing the performance metrics and PIMs in the Company's MYRP, PSE was guided by applicable legislation, including CETA and the criteria in SB 5295 for evaluating metrics and performance measures in MYRPs. PSE also considered that the Commission is just beginning a proceeding to develop policies concerning metrics and PIMs.

The Company intends that its MYRP proposal and evidence on metrics, PIMs, and other PBR provisions in its MYRP application help to inform the Commission's subsequent decisions on these issues. This evidence is not, however, intended to supplant the UTC's effort to fashion PBR policies. Cautious steps in the development of PIMs seem warranted until the Commission's generic proceeding advances. The Commission's generic proceeding may lay the foundation for new metrics and PIMs in the Company's subsequent MYRPs.

The development of the proposed metrics and PIMs was also influenced by PEG's appraisal of weak spots in the incentives included in typical utility regulatory systems. Another consideration was the input obtained from collaboration with UTC staff and stakeholders.

7.4 The Metrics Collaborative

PSE established a collaborative process to exchange ideas with stakeholders about metrics and PIMs for its MYRP. Participants in this process included the Alliance of Western Energy Consumers, Climate Solutions, the Energy Project, the NW Energy Coalition ("NWEC"), Public Counsel, and UTC staff. Four meetings were held between August 20 and November 15 of this year. PSE presented detailed draft metrics and PIMs in a meeting on October 8. NWEC presented a proposal in the meeting on November 15[43] that included PIMs in several areas such as DR and transportation electrification.

Notable takeaways from discussions with stakeholders included the following.

- Some stakeholders wanted to discuss PIMs and metric-target pairings, not just lists of metrics.
- Metrics and PIMs should target identified problems that require attention.
- Consumer groups questioned the need for PIMs with rewards.
- Several stakeholders espoused the view that PSE should not be rewarded for things that the Company is already incented or required to do. Incentives should encourage "new or

[43] NWEC, *PIMs and Metrics – Ideas and Discussion*. PSE PBR Stakeholder Meeting, 15 November 2021.

improved programs and services that utilities would not otherwise pursue." There should be a "rigorous baseline setting" and a "high bar of additionality."

7.5 Proposed Metrics and PIMs

Overview

The metrics and PIMs that the Company proposes for its MYRP are summarized in Table 1 below. A scorecard containing the proposed metrics is detailed in Table 2. This scorecard contains historical values for the metrics where they were readily available, and it also includes any targets or baselines that are proposed. Details of the metrics and targets are provided in Exh. MNL-4. In addition to service quality, it can be seen that metrics are proposed in the areas of affordability, DSM, electric vehicles, greenhouse gas emissions, and AMI. In keeping with the equity goals of CETA, metrics are reported in these areas for highly impacted communities and vulnerable populations as defined in the Washington Administrative Code where practical.

Table 1

Overview of Proposed Metrics and PIMs

Group	Systemwide	Highly-Impacted Communities and Vulnerable Populations
	Affordability	
Customer Cost and Affordability		Number of low income customers receiving bill assistance Share of bill assistance customers who are in highly impacted and vulnerable communities
	Demand-Side Management	
Customer Cost and Affordability; Environmental Impact	**Peak Load Management Savings (PIM)** Peak load management savings attributable to residential customers Annual energy efficiency savings (electric and gas)	Number of customers participating in gas and electric energy efficiency programs from highly impacted communities and vulnerable populations
	Electric Vehicles	
Customer Cost and Affordability; Environmental Impact	**Number of Residential and Fleet EV Chargers Used in Managed Charging Programs or TOU Rates (PIM)** Number of light-duty electric vehicles	Number of public charging ports serving highly impacted communities and vulnerable populations
	Greenhouse Gas Emissions	
Environmental Impact	CO_2 emissions from company-owned electric operations	
	Advanced Metering Infrastructure	
Environmental Impact	Reduced energy consumption from voltage reduction Remote switch success rate AMI bill read success (gas and electric)	
	Safety SQIs (several metrics, some PIMs)	
Service Quality & Safety		
	Customer Satisfaction SQIs (several metrics, some PIMs)	
Service Quality & Safety		
	Customer Service SQIs (several metrics, some PIMs)	
Service Quality & Safety		
	Field Operations SQIs (several metrics, some PIMs)	
Service Quality & Safety		
	Electric Service Reliability SQIs (several metrics, some PIMs)	
Service Quality & Safety	Revised SAIDI and SAIFI metrics for non-storm days	SAIDI and SAIFI metrics in highly impacted communities and vulnerable populations

Note: Items in bold text include PIMs

Pacific Economics Group Research, LLC

Table 2

Proposed PSE Scorecard

Current SQI Metrics

Category	Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Customer Satisfaction	Complaints per 1,000 Customers to the WUTC	0.18	0.2	0.16	0.16	0.1		Less than 0.4
	Customer Access Center Transactions Customer Satisfaction	93%	93%	94%	92%	94%		At least 90%
	Field Service Operations Transactions Customer Satisfaction	95%	94%	95%	95%	96%		At least 90%
Customer Service	Calls Answered by a Live Representative Within 60 Seconds of Request*	82%	82%	81%	81%	84%		At least 80%
	Percent of Appointments Kept	100%	100%	100%	100%	99%		At least 92%
Gas Safety	Average Gas Safety Response Time	31 minutes	32 minutes	30 minutes	32 minutes	32 minutes		No more than 55 minutes
Electric Safety	Average Electric Safety Response Time	55 minutes	55 minutes	52 minutes	54 minutes	51 minutes		No more than 55 minutes
Electric Reliability	SAIFI All Outages Current Year ($SAIFI_{TOTAL}$)	1.70 interruptions	1.80 interruptions	1.57 interruptions	1.57 interruptions	1.70 interruptions		No Target
	SAIFI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days (New $SAIFI_{SQI-4}$)	1.00 interruptions	1.12 interruptions	0.99 interruptions	0.98 interruptions	1.04 interruptions		1.2 interruptions
	SAIDI All Outages Current Year ($SAIDI_{TOTAL}$)	391 minutes	477 minutes	438 minutes	550 minutes	414 minutes		No Target
	SAIDI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days ($SAIDI_{SQI-3}$)	148 minutes	175 minutes	145 minutes	136 minutes	165 minutes		155 minutes

New SQI Metrics

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
SAIFI for HIC and VP, All Outages, Single Year	1.12	1.31	1.13	1.18	1.35		No Target
SAIFI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	0.75	0.88	0.77	0.74	0.84		No Target
SAIDI for HIC and VP, All Outages, Single Year	249	331	351	427	340		No Target
SAIDI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	105	143	116	111	141		No Target

Demand-Side Management

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Peak Load Management Savings (MW)	N/A	N/A	N/A	N/A	N/A		5
Peak Load Management Savings (MW) Attributable to Residential Customers	N/A	N/A	N/A	N/A	N/A		No Target
Annual Energy Efficiency Savings - Electric (MWh)	314,526	318,316	299,918	237,925	221,001		239,026
Annual Energy Efficiency Savings - Gas (Therms)	4,480,141	3,613,600	3,771,307	3,228,159	4,102,810		3,572,307
Number of Customers Participating in Gas and Electric Energy Efficiency Programs (Including Low-Income Programs) Who are from Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target

Electric Vehicles

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Number of Light-Duty Electric Vehicles in Service Territory	NA	NA	NA	NA	NA		No Target
Number of EV Chargers Used in Managed Load Programs or TOU Rates (Single-Family Residential)	NA	NA	NA	NA	NA		5,000
Number of EV Chargers Used in Managed Load Programs or TOU Rates (Fleet)	NA	NA	NA	NA	NA		47
Number of Public Charging Ports Serving HIC and VP	NA	NA	NA	NA	NA		No Target

Greenhouse Gas Emissions

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
CO_2 Emissions from Company-Owned Electric Operations	6,515,902	6,217,840	6,080,674	7,406,110	4,793,992		No Target

Advanced Metering Infrastructure

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
AMI Bill Read Success Rate - Electric	NA	NA	NA	99.68%	99.76%		No Target
AMI Bill Read Success Rate - Gas	NA	NA	NA	99.40%	99.43%		No Target
Remote Switch Success Rate	NA	NA	NA	NA	99.41%		No Target
Reduced Energy Consumption from Voltage Reductions (kWh)	3,319,625	0	2,127,882	343,748	3,931,329		6,000,000

Additional Equity Metrics

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Number of Low-Income Customers Receiving Bill Assistance (Gas and Electric)	NA	NA	NA	NA	NA		No Target
Share of Bill Assistance Customers who are in Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target

Values of "NA" indicate that historical data are not readily available. "No target" indicates that no target has been established for that metric in that year.

*In 2016 and 2017 this metric was the percentage of calls answered in 30 seconds. The target for this metric was 70%. The data reported for these years are consistent with the current metric.

Service Quality

Service quality metrics and PIMs were noted in Section 6.1 above to often be approved as part of MYRPs. The Company already has numerous service quality indicators ("SQIs"). Many of these have targets and some are linked to PIMs. Compensation of PSE employees is tied to SQI outcomes.

The Company is proposing some changes to its reliability metrics in this proceeding. SAIDI and SAIFI metrics would henceforth be reported using only the latest (2012) IEEE-1366 methodology for removing major event day outages. The Company is proposing its SAIFI metric be calculated similarly to the current SAIDI metric, using the IEEE-1366 methodology with adjustment for catastrophic events. To ensure comparability with past Company values for these metrics, the baseline values would be calculated beginning in 2014, a year subsequent to PSE's implementation of its Outage Management System and Customer Information System.

These reliability metrics would be separately reported for the system as a whole and for highly impacted communities and vulnerable populations. The draft scorecard shows that reliability tends to be higher in these communities. However, no targets are proposed for these metrics. Additional discussion of the new reliability SQIs can be found in the testimony of Company witness Catherine A. Koch, Exh. CAK-1T.

DSM

DSM should play a major role in meeting PSE's and Washington's decarbonization goals. In the short term, DSM can reduce the need for fossil fuels. In the longer term, it can reduce the need for cleaner but more costly energy alternatives. For these reasons, DSM figures prominently in the Company's CEIP. In the collaborative, some stakeholders opposed demand-side management PIMs on the grounds that the Company has legislative mandates to pursue cost-effective DSM. However, NWEC proposed a demand response ("DR") PIM with metrics that included MW of demand reduction from residential customers and the entire portfolio, winter and summer.

Demand Response PIM

The Company is proposing a metric, target, and PIM to encourage it to embrace DR. Eligible DR programs would include direct load control ("DLC"), interruptible (curtailable) load, and/or pricing programs designed to shift load from peak periods and reduce system peak demand. PSE would acquire these DR resources primarily through its Distributed Energy Resources / Demand Response Request for Proposal ("DER / DR RFP"), which the Company anticipates issuing in early 2022. To prevent any double-counting of payments, any EV loads that qualify for the EV PIM discussed further below would be excluded from the achievement levels used to establish performance under the DR PIM.

DR resources procured through PSE's own efforts — outside of the competitive procurement process — would also be included in the calculations. In Chapter 4 of its recently-filed CEIP, PSE states that it expects DLC programs to account initially for most or all of its DR resources. Nonetheless, the Company should be encouraged to implement other types of DR as well.

The specific metric to be tracked would be the expected MW reduction in the Company's need for planning reserves for the winter coincident peak demand. Effective DR capacity is a useful shorthand expression for this concept. Each program's impact on effective DR capacity would be estimated based on pre-established measurement and verification techniques.

PSE proposes annual incremental effective DR capacity targets of 5 MW in 2023, 6 MW in 2024, and 12 MW in 2025. These goals mirror those proposed in the Company's CEIP. Since the Company currently realizes no peak demand reductions through DR programs, these proposed targets represent a significant improvement.

PSE is proposing a PIM that would provide the Company a percentage of its estimated lifetime cost of developing and administering DR programs, including the payouts and administrative costs of its DER / DR RFP, depending on the incremental expected DR capacity it achieves. The Company would receive a payment only if it achieved at least 90 percent of its annual target. The payment percentage would be 15 percent for achievement levels of 90 percent through 110 percent of the annual target. This percentage would increase to 25 percent for achievement levels over 110 percent and up to 150 percent of the target. No additional reward would be provided for achievement levels in excess of 150 percent of the target. If the Company achieves less than 90 percent of its target, it foregoes any earnings opportunity. More details regarding the Company's proposed demand response PIM are provided in Exhibit MNL-5.

Establishing specific payment percentages is ultimately a matter of judgment. But it is important to remember that one of the justifications for a DR PIM is that the utility is potentially foregoing supply-side investments on which it would earn a return. Moreover, the installed costs of the investment would most likely exceed the DR expenses on which the PIM is based. The proposed PIM should be evaluated with that consideration in mind.

If the Company achieves at least 90 percent and no more than 110 percent of its target, then it would realize a payment of 15 percent of its expenses, which is roughly twice its weighted average cost of capital ("WACC"). The percentage payment should be higher than the WACC because:

- DR expenses will probably be less than the installed cost of supply-side resources offering similar capacity value;
- the utility deserves a premium payment if it performs well in an important new policy area (i.e., it should be financially better off than if it relied on supply-side resources for the same capacity); and
- PSE's achievement levels are less certain than they are for most other utilities, since PSE has little historical experience with DR.

By extension, if the utility performs very well (i.e., achieves more than 110 percent of its target) then it should receive a greater percentage payment to reflect superior performance. The cap on the total payment (at 150 percent of the target) will protect customers by imposing a ceiling on the total payment in any year.

In addition to establishing a metric, target, and PIM for effective DR capacity, the Company also proposes to track separately the residential contribution to this total. There would be no corresponding target or PIM for the residential class.

A focus on the winter peak makes sense since, for the foreseeable future, PSE expects to remain a winter-peaking utility. Although PSE is not proposing to establish a summer peak load metric at this time, the Company recognizes that higher air-conditioning saturation in its service territory will increase the importance of reducing summer coincident peak demand as well. Consequently, at some point PSE might propose adding a summer metric.

Other DSM-Related Metrics

PSE is also proposing tracker metrics on its scorecard for the incremental energy savings from its gas and electric energy efficiency programs. These data are routinely reported in other Company filings. The programs considered in these calculations would include conservation voltage regulation and grant projects. Targets have been established for these metrics.

The number of distinct residential and commercial customers participating in EE programs who are members of highly impacted communities or vulnerable populations would also be reported. In this calculation, EE programs open to the general public would be counted as well as those that focus on low-income customers. No target is proposed for this metric.

Transportation Electrification

The transportation sector is the largest source of GHG and hazardous air pollutants in Washington. These emissions harm the environment and some also degrade visibility and human health. Transportation electrification is accordingly a key goal of the State's clean energy initiative. Detrimental health impacts from nitrogen oxide and particulate vehicle emissions are likely greatest in the Seattle-Tacoma transportation corridor that PSE serves.

We noted in Section 7.1 that PSE has a well-established program for supporting the growth of EV loads. In this program, the Company typically owns the EVSE. Substitute House Bill 1512, signed in 2019, permits utilities to offer EV incentive programs that may include the promotion of EV adoption and advertising programs to promote the utility's services, incentives, or rebates.

The Company has managed the loads of its EV program participants where practicable. Single-family residences have been the primary focus of the Company's EV load management to date. Customers do not have to use a charger that is owned by PSE to participate in the managed load program.

PSE plans to expand its EV service offerings during the MYRP. Expansion of EV service to commercial customers and disadvantaged communities are priorities. Fleet customers are a promising candidate for managed loads. These customers may use level two chargers and/or DC fast chargers.

Substitute House Bill 1853, signed in 2015, encourages utility investment in EVSE, stating that "utilities… must be fully empowered and incentivized to be engaged in electrification of our transportation system." The incentive scheme detailed in the law is a modest 2% incentive rate of return on EVSE assets. EVSE capital expenditures cannot increase costs to ratepayers by more than 0.25%.[44] The Company proposes to embrace this incentive, as discussed in the testimony of William T. Einstein, Exh. WTE-1T.

The rising low carbon fuel standard that Washington's legislature has approved will boost utility funding for EV programs. However, the Company's funds from this source will be modest during the term of the proposed MYRP (2023-25), may only pertain to residential EV customers, and may have restricted uses. Some details of this program have not been finalized.

Revenue decoupling removes the incentive that PSE would otherwise have to build margins from EV load growth between rate cases. The Company has deferred its EV program expenses to date but is asking to recover these expenses in this rate case. The forecasted cost of EV programs in the next three years would be added to the revenue requirement and allocated to various service classes. However, in the absence of a tracker for the cost of EV service, the growth in this revenue requirement component is disconnected from the growth in EV charging which actually occurs. A new EV customer imposes a marginal delivery cost on the Company but may provide no corresponding marginal revenue to recover those costs between rate cases. There is no flexible funding for EV load growth that exceeds planned amounts.

Stakeholders in the collaborative metric discussions maintained that PSE has adequate incentives to promote EVs. They did, however, evince concern about the Company's incentive to manage EV loads cost-effectively. To that end, NWEC proposed a PIM for EV load management.

Proposed PIM

Given the general support expressed during the collaborative discussions, PSE is also proposing a PIM for electric vehicle load management. The metric is the number of new chargers installed in a given calendar year and served under either a load management program or TOU rates, including the Company's proposed Time Varying Rate ("TVR") program. In the operation of the PIM the Company proposes metrics and targets for the following types of chargers:

- Level 2 Chargers used in single family residences;
- Level 2 Chargers used for fleets; and
- DC Fast Chargers used for fleets.

The award rate in the proposed PIM would be based on the expected net benefits of each new installation. These net benefits vary significantly depending on the type of charger (Level 2 or Fast Charger) and its application (single family residence or fleet). Consequently, it is important to track not only the total number of new chargers, but also the number of chargers in each of the three distinct categories.

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[44] RCW 80.28.360 (1).

The benefits of encouraging customers to charge during off-peak periods are not contingent on Company ownership. Consequently, the Company proposes that the targets and rewards be applied to chargers owned by the Company, customers or third parties. This approach can incentivize the Company to encourage customers with chargers owned by themselves or third parties to participate in load management or TOU rates.

The Company would earn a reward in any given year only if the number of new chargers installed in one or more of the three categories exceeded the target for that category or categories for that year. The reward would be provided only for new installations in excess of the target. For example, if the target in 2023 was 100 chargers and the Company installed 102 chargers during that year, then the Company would earn a reward only for the two chargers in excess of the target.

In the calculation of net benefits, the gross benefits would consist of the:

- avoided energy costs,
- avoided generation capacity costs, and
- avoided transmission and distribution capacity costs.

The expected avoided costs represent the cost impact of the managed load program or TOU pricing on the EV load shape. In other words, they represent the difference between the cost of serving an EV charging load under a managed load program or TOU rates and the cost of serving the same charger assuming no managed load program or TOU rates.

The costs would consist of the *incremental* administrative and other costs that the Company incurs to serve the charging load under a managed load program or TOU rates. These other expenses would include any incentive payments to customers to encourage them to place their charging loads on managed load programs or TOU rates.

These incremental costs would exclude the majority of the costs of developing and administering the load management or TOU pricing option. Instead, the costs used to calculate net benefits would be limited to the incremental costs of serving an additional charger under the load management program or TOU rates.

The expected benefits and costs per charger described would be estimated over five years. The present value of the five-year stream of costs would then be subtracted from the present value of the stream of benefits to yield a single dollar reward for each installed charger in excess of the target. A distinct dollar award per installation would be established for each of the three categories of chargers.

It is important to remember that the purpose of this proposed PIM is not simply to encourage more chargers per se, but to encourage customers who do install chargers to charge during off-peak periods — when energy and capacity costs are lower. As mentioned previously, this usage shift was a priority for stakeholders in the metrics collaborative as well. Other mechanisms (such as a premium return on equity of 200 basis points for EV-related investments) encourage the Company to install more chargers. Consequently, the impacts used to establish the reward are limited to the impacts of encouraging off-peak charging. Those impacts do not include the net environmental benefits of reducing the emissions from internal combustion engines or the cost of installing a charger.

One of the primary advantages of basing the reward on a percentage of net benefits is that customers are expected to benefit when the Company exceeds its target(s) as long as the percentage reward to the Company is less than 100 percent. A potential disadvantage of using net benefits is that calculating the actual net benefits can be very time-consuming and administratively burdensome. Such a derivation would require analyses of actual load shifts and actual avoided costs based on these load shifts. To avoid these potentially high costs the Company proposes to use pre-established estimates of load shifts and the concomitant avoided costs over a five-year period. We believe that any reduction in accuracy attributable to using estimates is outweighed by the increased simplicity and reduced costs of administering the PIM.

The justification for a reward-only EV PIM is similar to the justification for using a reward-only structure for DR. In both cases the Company is challenged with a new performance expectation that goes beyond satisfying customers' basic service requirements. In addition, in both cases the Company is being encouraged to take steps that tend to reduce rate base and earnings.

PSE proposes that the PIM be effective for calendar years 2023, 2024 and 2025. Of course, the Company may later propose an extension of the PIM, either as approved in this proceeding or with modifications. The Commission's decision in this proceeding should be issued before the first year of the PIM, 2023.

PSE is still in the process of developing its EV charging targets and anticipates that these targets will be established sometime in the first quarter of 2022. Once these targets are available, the proposed PIM can be set forth in more detail.

In summary, PSE proposes a reward-only PIM that is based on the number of new EV chargers that are installed in a given year and used to provide service under either a managed load program or TOU rates. The reward would apply to all installations in excess of the target established for that year and would be based on a pre-determined estimate of lifetime net benefits per charger. Separate targets and rewards would be established for single-family residences using Level 2 chargers, fleets using Level 2 Chargers, and fleets using Fast Chargers. The Company will not be positioned to propose specific targets and sharing percentages until later in the first quarter. Exh. MNL-5 provides a summary of how the PIM would be developed.

Other EV Metrics

The MYRP scorecard would also include two EV-related tracker metrics. One is the estimated number of light-duty plug-in electric vehicles (battery-only or hybrid) in the Company's service territory. This would be calculated using Washington Department of Licensing data on EVs registered in zip code tabulation areas in which PSE offers electric service. The Company also proposes to track the number of publicly-available charging ports in highly impacted communities and vulnerable populations. PSE will continue to report a wider array of EV metrics in other venues.

Emissions

PSE is preparing to comply with the decarbonization goals of CETA which call for the retail sales of each Washington electric utility to be GHG neutral by 2030. There is no explicit provision in the law for how much progress towards this goal PSE must make during its first MYRP. The GHG emissions from the Company's generation are volatile, driven by external business conditions such as weather, the business cycle, and the availability of hydroelectric and other kinds of renewable energy resources. This increases the risk of an emissions PIM.

The Company proposes to track the metric tons of Scope 1 emissions from its own generation. This information is reported annually to the Environmental Protection Agency and the UTC. No target is proposed.

AMI

The UTC's decision in the recent Avista rate case indicates an interest in AMI performance metrics.

> To demonstrate the benefits of AMI, Avista should be required (1) to develop and report further analyses of the use cases: TOU rates, real-time energy use feedback for customers, behavior-based programs, data disaggregation, grid-interactive efficient buildings, CVR or volt/VAR optimization; (2) to craft and report plans for achieving benefits through each of these use cases; and (3) to develop and propose AMI performance-based regulation metrics and measurements that the Commission might apply, and specifically such metrics and measurements for each of these use cases.[45]

PSE is in the middle of a systemwide AMI buildout. This makes AMI metrics topical but limits the availability of data. The Company is proposing to include three AMI metrics in its MYRP scorecard. These metrics address the functionality of the AMI and its voltage impact.

<u>Bill Read Success:</u> The most fundamental job of AMI is to automatically forward data on customer billing determinants. The proposed Bill Read Success metric would measure whether the AMI delivers a meter read to PSE's data system, as expected each cycle. This would be calculated and reported separately for gas and electric meters. A 99.5% success rate target is proposed for each plan year beginning in 2024.

<u>Remote Switch Success:</u> AMI makes it possible to turn service off and on quickly and without truck rolls. The proposed Remote Switch Success metric would measure the functionality of the switch when a command is made from the command center by PSE. Calculation would be limited to customer-initiated requests. This would be reported only for electric service. The proposed target is a 99% success rate beginning in 2024.

<u>Voltage Reduction:</u> The voltage on a distribution circuit must attain a minimum standard for every customer. AMI improves knowledge of the voltage at which each customer on a

[45] WUTC (2021), Final Order 08/05, p. 127.

distribution circuit is served. This can make it possible to reduce voltage on the circuit at the substation. The proposed Voltage Reduction metric would measure the reduction in KWh accomplished. The proposed target for 2023 is 6,000,000 kWh.

No AMI PIMs are proposed. The Company will report additional AMI metrics routinely in other venues. AMI metrics are discussed further in the testimony of Company witness Catherine A. Koch, Exh. CAK-1T.

Additional Equity Metrics

We have already noted the metrics on the scorecard for reliability, public EV charging stations, and EE program participation in highly impacted communities and vulnerable populations. The Company also proposes two metrics that address the affordability of service to disadvantaged customers. One is the number of distinct customers receiving bill assistance from qualified low-income programs. The qualifying programs include the low-income energy assistance program ("LIHEAP"), PSE's Home Energy Lifeline Program ("HELP"), the Salvation Army warm home fund, the proposed arrearage management program, and the proposed bill discount rate. The Company will also report the share of these bill assistance customers who are members of highly impacted communities and vulnerable populations. The Company will report a range of customer benefit indicators in other venues.

7.6 Appraisal of the Company's MYRP Proposal

An appraisal of an MYRP proposal should consider several dimensions. One is its fairness. A second is its effect on utility performance incentives. A third is its effect on regulatory efficiency. It is also pertinent to consider the extent to which SB 5295 ties the hands of the Commission in approving MYRP plans.

Fairness of the Company's Proposal

We believe that PSE's proposal strikes a fair balance between the interests of the Company and its customers. There are some benefits for PSE. For example, revenue growth would be based on the Company's financial plan, timely, and subject to an adjustment for any unforeseen inflation. Revenue decoupling would reduce the risk of volatility in billing determinants. Subject to statutory limitations, PSE could file a rate case if it underearns.

However, the framework also provides extensive customer protections, including the following.

- The Commission would decide the extent to which it would fund PSE's budgeted cost growth. The Company would be obliged to operate under the Commission-approved revenue requirement for two years.
- Revenue to reimburse PSE for the annual cost of its capex during the plan may be refunded to customers if the assets are later found not to be used and useful or their cost is deemed imprudent.
- The ESM would asymmetrically favor customers. The entirety of weather-normalized earnings in excess of a modest 50 basis point dead band would be returned to customers. In

contrast, many approved MYRPs have wider dead bands and/or afford utilities a share of surplus earnings beyond the dead band. Some plans do not have any ESM. In the event of underearning, PSE would absorb the entirety of any ROE shortfall until and unless it is granted some rate relief in year three after a rate case. In contrast, some approved MYRPs have automatically shared underearnings with customers.

- PSE would absorb the risk of fluctuations in loads for some large-volume customers.
- Rate growth would be more predictable.
- The term of the MYRP would only be three years.

Cost Control Incentives

The Company's cost control incentives would be strengthened by the MYRP on balance. The PSE MYRP would provide significant incentives to contain O&M expenses (or "opex") since revenue growth for these kinds of costs is linked to expected rather than actual cost growth between rate cases. Under continued COSR, PSE would be free to file a rate case at any time. Given its need to modernize the grid, improve reliability, and supply cleaner energy, PSE would likely file cases frequently. It would likely also continue to be subject to earnings sharing.

The Company's ability to file a rate case during the MYRP is a fairly unusual feature of the framework. However, there are similar provisions in the new PBR law in North Carolina. Many approved MYRPs have off-ramp provisions, as we noted in Section 6.1 above.

Moreover, the proposed provision is unlikely to trigger a rate case. Given the three-year plan period, the Company would likely file a rate case anyways in Year 3 in order to have new rates effective upon the expiration of the plan. We should also note that this provision only gives PSE the *right* to file a rate case. In our experience, small and temporary underearnings rarely prompt a utility to file a rate case. The decision to file a rate case is based on several factors including the magnitude of the earnings deficiency, forecasted changes in costs or revenues, expectations of changes in the authorized rate of return resulting from a potential rate case, the ability to seek supplemental revenue through deferrals or cost trackers, and political considerations. PSE might not file a case even if it is eligible to do so because the situation is expected to be temporary, and it is in the Company's long-term interest to make MYRPs work.

Regulatory Efficiency

MYRPs should improve the efficiency of regulation and the Company's MYRP can accomplish this, first and foremost by reducing the frequency of rate cases. Regulatory resources would thereby be freed up to focus more on PSE's capex and clean energy plans, rate designs, and miscellaneous generic issues. This is a notable advantage in a period of rapid change when the UTC must contend with a swirl of issues. Of course, the magnitude of these benefits will depend on the other filings and processes that are required as part of, or in conjunction with, the MYRP.

Other Goals

The goals of utility regulation extend beyond ensuring that the Company provides service of reasonable quality at a reasonable price. In Washington, the impact of utility operations on the environment and disadvantaged groups are of special interest. PSE is subject to legislative mandates to decarbonize its energy supply, aggressively pursue DSM opportunities, and spread benefits of the energy transition equitably. The Company's MYRP proposal encourages attention to these other goals through revenue decoupling and its scorecard of metrics and PIMs.

Commission Independence

Legislation in several states has detailed a particular approach to Altreg and limited regulatory commission discretion to choose a different approach to regulation. The Washington MYRP law, in contrast, gives the Commission considerable discretion over the design of any plans that are implemented.

Appendix

A.1 Glossary of Terms

Advanced Metering Infrastructure ("AMI"): An integrated system of smart meters, communications networks, and data management systems that enables rapid two-way communication between the utility and customers.

Alternative Regulation ("Altreg"): Approaches to utility regulation that differ from the traditional North American cost of service regulation. Examples of alternative regulation include performance-based regulation, forward test years, formula rate plans, and diminished roles for volumetric charges in rate design.

Base Rates: The components of a utility's rates that provide compensation for costs of non-energy inputs such as labor, materials, services, and capital.

Beneficial Electrification: Replacement of fossil fuel technologies with those that rely on electric power for the benefit of the environment.

Capex: Capital expenditures.

Cost of Service Regulation ("COSR"): The traditional North American approach to utility regulation that resets base rates in occasional rate cases to reflect the costs of its service that regulators deem prudent.

Cost Tracker: A mechanism providing expedited recovery of targeted costs that are approved by regulators. A tracker is an account of costs that are eligible for recovery. Balances that are deemed prudent by regulators are then typically recovered via rate riders or deferred for future recovery. Tracker treatment was traditionally limited to costs that are large, volatile, and largely beyond the control of the utility. In more recent years, trackers have been used to address various rapidly rising costs, and costs of underused practices.

Distributed Energy Resources ("DERs"): Technologies, services, and practices that can improve efficiency or generate, manage, or store energy on the customer side of the meter. DERs can include energy efficiency and demand response programs, distributed generation, energy management systems, batteries, and more. DERs can be implemented by utilities, customers, third-party vendors, or combinations thereof.

Earnings Sharing Mechanism ("ESM"): An ESM automatically shares surplus or deficit earnings (or both), between utilities and customers, which result when the rate of return on equity deviates materially from its commission-approved target. ESMs often have dead bands in which earnings variances aren't shared.

Efficiency Carryover Mechanism ("ECM"): A mechanism that allows for a share of lasting performance gains or losses achieved under a multiyear rate plan to be kept by the utility for a period of time after the plan expires.

Electric Vehicle Supply Equipment ("EVSE"): Equipment that supplies electricity to an electric vehicle.

Federal Energy Regulatory Commission (“FERC”): The federal agency responsible for regulation of rates and services for utilities engaged in interstate commerce including electric transmission, wholesale power sales, natural gas pipeline transportation, natural gas storage facilities, and LNG facilities.

Greenhouse Gas (“GHG”): A gas that contributes to the greenhouse effect by absorbing infrared radiation. Notable examples of greenhouse gases are carbon dioxide, methane, and ozone.

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Typically accomplished via light regulation of rates and services with certain attributes. Services that have been deemed eligible for flexibility include optional tariffs for standard services, optional value-added (aka discretionary) services, and services to competitive markets. Price floors are sometimes established for eligible services to discourage predation and cross-subsidization.

Multi-Year Rate Plan (“MYRP”): A common approach to PBR that typically features a multiyear rate case moratorium, a revenue adjustment mechanism, and several PIMs.

Off-Ramp Mechanism: An MYRP provision that permits the reconsideration or suspension of an MYRP under pre-specified conditions (e.g., persistent, extreme ROEs).

Ofgem: British Office of Gas and Electricity Markets, the regulator of gas and electric utilities in Great Britain.

Performance-Based Regulation (“PBR”): An approach to rate regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism (“PIM”): A mechanism consisting of one or more metrics, targets, and financial incentives (rewards and/or penalties) which is designed to strengthen performance incentives in targeted areas such as service quality.

Performance Metric System: A system of metrics used to appraise the performance of a utility in one or more service areas (e.g., reliability, environmental performance, or cost). Performance metric systems may include metrics without targets, metrics with targets, and performance incentive mechanisms.

Productivity: The ratio of outputs to inputs is a rough measure of operating efficiency that controls for impact of input prices and operating scale on cost. Productivity may be measured for all inputs or just for O&M or capital inputs.

Rate Base: In the calculation of the revenue requirement, the rate base is the value of plant (and related items) on which the utility earns a pro forma return. In large part, it typically reflects the net historical value of plant and an adjustment for accumulated deferred income taxes.

Rate Case: A proceeding to reset a utility’s revenue requirement to reflect its cost of service. These proceedings may also consider other issues such as rate designs.

Rate Case Moratorium: A set period of time during which a utility is not allowed to, or agrees not to, file a rate case.

Rate Rider: A mechanism, frequently outlined on tariff sheets, which allows a utility to receive rate adjustments between rate cases.

<u>Return on Equity ("ROE")</u>: The rate of return on the value of equity capital invested.

<u>Revenue Adjustment Mechanism ("RAM")</u>: A common component of multiyear rate plans that automatically adjusts rates or revenues to address utility cost pressures between rate cases without closely tracking the growth of all of the utility's *own* costs. Methods used to design RAMs include forecasts and indexation to quantifiable external cost drivers such as inflation and customer growth. These mechanisms are also typically combined with revenue decoupling in regulatory systems that lack such plans.

<u>Revenue Cap Index</u>: A formula that typically includes an inflation index which is used to escalate allowed revenue in multiyear rate plans.

<u>Revenue Decoupling Mechanism</u>: A mechanism for relaxing the link between a utility's revenue and use of its system which makes periodic rate adjustments to ensure that actual revenue closely tracks allowed revenue. A companion revenue adjustment mechanism typically escalates allowed revenue between rate cases for growing cost pressures.

<u>Revenue Requirement</u>: The annual revenue that the utility is entitled to collect. The amount is periodically recalculated in rate cases to reflect utility cost and may be escalated by other mechanisms (e.g., cost trackers and RAMs) between rate cases. The corresponding cost is typically the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base less other operating revenues.

<u>RIIO</u>: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MYRPs that include relatively long rate case moratoria, a forecast-based RAM, and an extensive and innovative set of PIMs.

<u>Scorecard</u>: A summary of a utility's performance on various metrics in a performance metric system. This summary is often reported on a publicly-available website.

<u>Test Year</u>: A specific period in which a utility's costs and billing determinants are considered in a rate case to establish new rates. Some states use a historical test year and adjust billing determinants and costs for known and measurable changes. Other states use a fully forecasted test year that considers other possible changes.

<u>Throughput Incentive</u>: Under traditional regulation, utilities can increase revenues by increasing sales between rate cases. Increased sales will in turn result in increased profits for the utility because the marginal cost of providing additional service is typically well below the rate per unit of use.

<u>Total Expenditure</u>: Under RIIO, capital expenditures and operating expenditures are combined into one category: "total expenditures," or "totex" when setting the revenue requirement. The utility earns a return on a pre-determined portion of totex, regardless of whether the utility's capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus non-capital projects.

X-Factor (aka Productivity Factor): A term in an index-based RAM formula that reflects the typical impact of productivity growth on utility cost growth. It may also incorporate an adjustment for the inaccuracy of the inflation measure.

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