Performance-Based Regulation Report With Recommendations

for The Maine Public Utilities Commission

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June 27, 2025

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STATE OF MAINE
PUBLIC UTILITIES COMMISSION

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June 27, 2025

Honorable Mark W. Lawrence, Senate Chair
Honorable Melanie Sachs, House Chair
Members, Joint Standing Committee on Energy, Utilities and Technology
100 State House Station
Augusta, Maine 04333

Re: Performance-Based Regulation – Christensen Associates Report

Dear Senator Lawrence, Representative Sachs, and Members of the Joint Standing Committee on Energy, Utilities and Technology (Committee):

The Commission respectfully submits the enclosed report *Performance-Based Regulation Report With Recommendations* prepared by Christensen Associates Energy Consulting (the "Report"). The Commission retained Christensen to assist in examining performance-based tools for regulating Maine's investor-owned transmission and distribution utilities.[1]

Christensen initially prepared a draft report, dated April 29, 2025, which presented its draft findings regarding performance-based regulation (PBR) for the state's electric utilities. The Commission then opened an inquiry, and on May 16, 2025, held a stakeholder workshop allowing stakeholders to ask questions and provide input on the draft report.[2] In particular, the Commission sought input on the goals of PBR for Maine's investor-owned utilities. Stakeholders who attended the workshop included the Office of the Public Advocate; the Governor's Energy Office; Efficiency Maine Trust; Central Maine Power Company; and Versant Power. Later in May, stakeholders had the opportunity to submit written comments regarding the draft report.[3] Written comments were filed by Synapse Energy Economics, Inc., on behalf of the Office of the Public Advocate; Efficiency Maine Trust; AARP Maine; Central Maine Power Company; and Versant Power. With this stakeholder input, Christensen finalized its Report. In addition to Christensen's findings, the final report includes Christensen's recommendations for performance-based regulation.

[1] The 131st Legislature considered ,but did not enact, L.D. 2172 ,*An Act to Enhance Electric Utility Regulation Based on Performance*. That Act would have required the Report. Regardless, given the significance of the topic of performance-based ratemaking and that the Commission received a letter from Senator Lawrence, Representative Zeigler and Representative Runte (then EUT Chairs and a Committee member) requesting this work be undertaken the Commission moved forward with this work.

[2] The inquiry was conducted under Docket No. 2025-00107, which may be found at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2025-00107. Approximately 600 people were notified of the inquiry and the opportunity to participate.

[3] Stakeholders had this opportunity regardless of whether they attended the workshop.

The Commission's submission of the Report includes:

- The Report;
- A transcript of the May 16, 2025, Workshop;
- A May 22, 2025, Procedural Order attaching the slides that Christensen presented during the Workshop;
- All written comments; and
- The April 18, 2024, Letter from Representative Runte, Representative Zeigler, and Senator Lawrence

The Commission appreciates Christensen's work, the contributions of stakeholders, and the opportunity to provide the Committee with this information. The Commission believes that the Report contains valuable recommendations, and the Commission intends to carefully consider the Report's guidance in the context of distribution rate cases. The Commission does not anticipate the need for further Legislative action related to performance-based regulation.

The Commission remains available if the Committee has questions or requires additional information.

Sincerely,

Philip L. Bartlett II

cc: Lindsay Laxon, Legislative Analyst, Office of Policy and Legal Analysis

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EXECUTIVE SUMMARY

The purpose of the study is to evaluate the Performance Based Regulation (PBR) tools that may be used to regulate investor-owned electric utilities (IOUs) in the state of Maine.

One of the central findings of this report is that the Maine Public Utilities Commission (MPUC) has already incorporated several PBR elements into its ratemaking structure. The MPUC currently regulates the state's IOUs with Performance Incentive Mechanisms (PIMs) in the form of Service Quality Indicators (SQIs), which apply to both utilities. The IOUs also have the option to file Multi-Year Rate Plans (MYRPs), such as Central Maine Power's (CMP) current MYRP and the company's former price cap. Furthermore, Maine's utilities have implemented other alternative regulation tools such as Earnings Sharing Mechanisms (ESMs) and revenue decoupling.

PBR tools have been used in other jurisdictions to address policy initiatives similar to the objectives of the MPUC. Some of these regulatory approaches could be introduced to Maine, and others that are optional could be formalized or made mandatory. For example, by formalizing a basic structure for MYRPs and requiring the state's utilities to follow this structure, the MPUC could create a regulatory framework in which utilities might gain more predictable revenues and obtain stronger incentives for cost control and innovation, while consumers might benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared. New PIMs can be used to target specific policy objectives like resiliency, greenhouse gas emissions reduction, and renewable energy connections.

However, while the adoption of PBR tools may provide improvements to the status quo regulatory framework in Maine, the introduction of new PBR tools would not guarantee such improvements. The realization of benefits from PBR requires a well-structured design that accounts for the particular circumstances of the jurisdiction or utility. For this reason, while case studies offer valuable insights, a plan that was successful for one utility will not necessarily replicate that success if applied identically to a different utility or in a different jurisdiction.

Performance Incentive Mechanisms

A PIM is a PBR tool involving an annual revenue adjustment mechanism that ties financial incentives to the achievement of pre-defined benchmarks or targets. PIMs can be reward-only, penalty-only, or symmetric, meaning they could result in both a reward and a penalty. Typically, PIMs operate by adjusting a utility's return on equity (ROE), though in some cases a pre-determined dollar value is used for a penalty or reward.

Generally, regulators and utilities institute PIMs after identifying specific, targeted policy goals related to utility outputs. This involves establishing metrics, defining achievement thresholds, and setting financial rewards or penalties. The implementation of PIMs requires careful design to ensure they effectively drive desired outcomes without unintended consequences. Key considerations include selecting metrics that are meaningful, measurable, and within the utility's control; setting challenging but achievable targets; and determining the magnitude of financial incentives that will motivate utilities without unduly burdening ratepayers.

One question about the design of PIMs is whether to make the financial incentive a reward, a penalty, or financially symmetric — meaning that the PIM offers a reward for positive achievement and a penalty of sub-par achievement. An approach to answering this question is to offer a reward if the utility has not been expected to produce the output in the past, since the cost is not reflected in rates, and a penalty if the utility is traditionally expected to provide the output.

The SQIs currently in place for Maine's utilities are PIMs in all but name. They have a clear performance target that the utilities must maintain and failure to maintain these performance targets results in penalties. Building on foundation established through existing reliability and customer service PIMs (SQIs), Maine could use PIMs to advance additional policy priorities and innovation. We recommend that the MPUC, the regulated utilities, and stakeholders collaborate to prioritize which policy goals (see Section 7.3) are currently unaddressed by the state's regulatory framework and establish metrics that reflect the achievement of these goals. Experience from jurisdictions using reward PIMs to promote key policy goals explored in Subsection 4.6 may be informative to Maine.

Table ES.1 offers recommendations regarding PIMs in Maine.

Table ES.1: Recommendations for PIMs in Maine

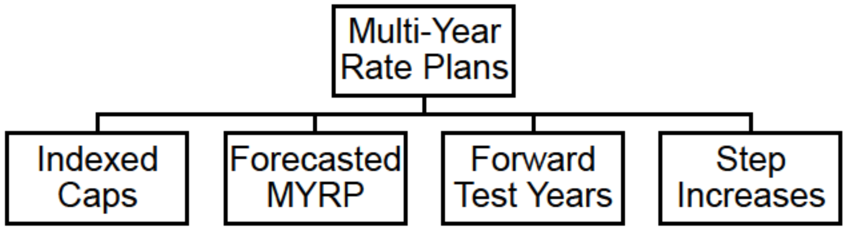
Recommendations for PIMs in Maine	*1. We recommend that the Maine PUC allow the state's IOUs to file new PIMs as part of future rate applications, to be assessed on a case-by-case basis. We recommend using the guidelines provided in Section 4.2 in the design of these PIMs.* *2. We recommend that before instituting any mandatory PIMs or any PIMs that apply to all IOUs, the Maine PUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. We recommend following the criteria set out in Section 4.2 prior to implementing mandatory PIMs.*

Multi-Year Rate Plans

MYRPs are a category of alternative regulation tools that provide a framework for setting rates that can reduce the frequency of utility rate cases, facilitated by rate adjustments that either follow industry cost and productivity trends or align with the company's own costs—actual or forecasted. Thus, rather than establishing static rates that remain in effect until a future rate case—as under traditional Cost of Service Regulation (COSR)—a MYRP sets a schedule or formula that allows rates to change over the plan period. It is not until the end of the MYRP period that rates are reset through a comprehensive cost-based rate case. Most MYRP terms last three to five years.

Figure ES.1 depicts several categories of MYRPs that are currently used by utilities in North America.

Figure ES.1: Forms of MYRP



The regulated electric utilities in Maine already have the opportunity to file MYRPs in the form of an Alternative Rate Plan, and as such, the state of Maine already has some past experience with MYRPs. Central Maine Power (CMP) operated under a price cap, which is a form of indexed cap, until 2013. CMP is currently operating under a two-year alternative rate plan.

Other jurisdictions, like those in Canada, Australia, and Great Britain, have developed standardized MYRP models that all utilities within the jurisdiction must follow. However, these jurisdictions generally contain many more distribution utilities than Maine. Rather than mandating a standard MYRP template that both utilities must follow, the MPUC could consider creating a general set of requirements that CMP and Versant Power must follow if they file a MYRP. This could be a highly structured, detailed set of rules that must be followed if the IOU elects to file a forecasted or indexed cap MYRP. Alternatively, the MPUC could adopt a high-level set of principles. Section 5 of this report contains recommendations for rules or principles to be followed for both indexed cap and forecasted MYRPs.

Cost efficiency incentives through MYRPs may help with affordability but will not resolve all factors driving customer rate increases. A substantial portion of rates paid by end users pertain to generation services, which Maine's IOUs do not provide.

Table ES.2, we encourage the adoption of forecasted and indexed cap MYRPs.

Table ES.2: Recommendations for MYRPs in Maine

Recommendations for MYRPs in Maine	*Maine IOUs are already permitted to file MYRPs as an alternative rate plan. To provide cost efficiency incentives to the utilities, we encourage the adoption of either forecasted or indexed cap MYRPs.* *Furthermore, we note that, as "lines-only" utilities, IOUs in Maine may be well-suited for indexed cap (price cap, revenue cap, or hybrid) PBR frameworks, as these plans provide cost efficiency incentives that may improve customer affordability. We therefore encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans (with further recommendations in Table 8.4).*

Other Alternative Regulation Tools

The industry acknowledges that PBR is not a binary term, and that some tools that are considered "alternative" to traditional regulation do not necessarily provide enhanced efficiency incentives to utilities. Alternative regulation tools include formula rates, capital trackers, totex, revenue decoupling, ESMs. While these tools are useful in certain circumstances, their application does not necessarily provide the same enhanced efficiency incentives to utilities as, for example, indexed cap MYRPs.

Some of these tools, such as CMP's ESM and revenue decoupling for both IOUs, are already used in Maine. ESMs manage the risk of a utility over- or under-earning relative to its allowed ROE. Utilities operating with ESMs share earnings that exceed (or fall short of) a predetermined threshold, either reducing rates for customers in the case of overearning or, depending on the design, providing financial relief to utilities in the event of underearning. ESMs are a form of alternative regulation distinct from PBR because ESMs relink the utility's revenues and costs, removing or mitigating cost efficiency incentives. However, ESM are often included in PBR plans as a means of managing risk.

Revenue decoupling is a regulatory mechanism used in the electric utility industry to separate a utility's revenue from its sales volume. Traditionally, utility profits were directly tied to the amount of electricity sold, creating an inherent incentive for utilities to promote increased energy consumption. Decoupling breaks this link, allowing utilities to recover their fixed costs and earn a fair return on investment regardless of fluctuations in electricity sales.

1 INTRODUCTION

1.1 Background and Scope of Work

The Maine Public Utilities Commission (MPUC) has directed Christensen Associates Energy Consulting (CA Energy Consulting) to assist with examining performance-based tools for regulating the state's investor-owned transmission and distribution utilities. This report presents our findings and recommendations for the applicability of performance-based regulation (PBR) for the state's electric utilities. The study addresses Multi-Year Rate Plans (MYRPs) including indexed revenue formulas, and Performance Incentive Mechanisms (PIMs). These are, with minor exceptions, the primary PBR tools used by electric utilities in North America.

The purpose of the study is to evaluate the PBR tools that may be used to regulate investor-owned electric utilities (IOUs) in the state of Maine. The scope of work for this project includes:

1. Conduct a comprehensive review of the standards and metrics utilized in other states that have implemented performance-based rate design, including an evaluation of the outcomes that resulted from the imposition of performance-based standards and metrics on the utility;
2. Assist the Commission in developing goals for utility performance and translate these goals into performance-based standards and metrics;
3. Identify any emerging regulatory mechanisms that would better align utility performance with state policies and goals when compared to other traditional forms of regulation;
4. Participate in stakeholder meetings, where necessary; and
5. Provide a detailed report to the Commission.

To understand potential regulatory changes in Maine requires a review of current ratemaking practices by utilities within the jurisdiction of the MPUC. Identifying potential beneficial changes to this paradigm also requires a review of PBR tools and methods used in other jurisdictions, a discussion of related economic theory, and results from engagement with stakeholders in the state of Maine. Our approach makes recommendations for updates to the state's existing regulatory framework only after this analysis. For each PBR tool discussed herein, we also discuss best practices for implementation, weighing the costs, benefits, and risks.

The organization of the report is as follows. This first section of the report explains the reason for the report, qualifications of the research team, and recommendations for how to use the remainder of the report. Section 2 presents fundamental concepts of rate regulation, comparing and contrasting traditional regulation with PBR. Sections 3 through 5 present a description of typical PBR mechanisms, including discussions of the economic principles supporting each tool and a review of jurisdictions where those tools are currently in place. Section 6 describes other tools in alternative regulation. Section 7 provides an overview of Maine's current regulatory framework and assesses possible updates. Section 8 concludes with a summary of findings and our recommendations.

1.2 Qualifications of the Project Team

Christensen Associates and its wholly owned subsidiary, Christensen Associates Energy Consulting (CA Energy Consulting), have over 40 years of experience in the design and application of incentive regulation plans across network industries, including electricity, gas, telecommunications, and postal industries.[1] The key team members for the project are Mr. Nicholas Crowley, Dr. Sherry Wang, and Mr. Andis Romanovs-Malovrh.

Mr. Nicholas Crowley, CFA, is a Vice President with Christensen Associates and has been with the firm since 2016. He has filed testimony on incentive regulation in both the United States and Canada and has filed reports and testimony on incentive regulation in Ontario, Alberta, British Columbia, New Hampshire, and Massachusetts. Prior to joining this firm, Mr. Crowley was an economist in the Department of Pipeline Regulation at the Federal Energy Regulatory Commission (FERC), where he assisted with energy industry benchmarking, the price cap regulation of oil pipelines, and the review and evaluation of natural gas pipeline rate cases. In these roles, Mr. Crowley worked extensively with FERC data, and other federal data, for the development of cost benchmarks for power systems, in measuring industry Total Factor Productivity (TFP) growth, and the development of incentive regulation plans. Mr. Crowley has a Master of Science degree in economics and a Bachelor of Science degree in economics, both from the University of Wisconsin-Madison, and he is a CFA charterholder.

Xueting (Sherry) Wang, PhD, is an Economist. She has conducted research of Performance Incentive Mechanisms on behalf of both regulators and utilities. Dr. Wang also has experience in a variety of areas related to utility ratemaking including reviewing cost-of-service methodology, rate class determination, building rate design models, conducting bill impact analysis, and estimating customer load response to changing prices. Her doctoral research at Columbia University focused on energy and environmental economics.

Andis Romanovs-Malovrh is an Economist with Christensen Associates and has been with the firm since 2023. He has provided support in performance-based regulation projects in Ontario and Indiana and has assisted in extracting and processing utility factor productivity data. Andis also helps estimate load impacts in response to residential air condition load control and critical peak pricing programs as well as time-varying electric rates. Andis has a Master of Arts degree in economics and a Bachelor of Arts degree in economics from Riga Technical University.

Corey Goodrich is a Staff Economist at Christensen Associates. His work includes analyzing customer response to dynamic and time-vary electricity rates, evaluating load impacts of demand response programs, stakeholder feedback, and supporting utility rate applications. Prior to working at the firm, Corey worked in both academia and government. He has co-authored academic publications and performed evaluations of state workforce programs. His research has been published in journals such as *Applied Economics*, *Applied Economic Letters*, *and The BE Journal of Economic Analysis & Policy*. Corey has a Master of Arts degree in economics from the University of South Florida and a Bachelor of Arts degree in economics from the University of Wisconsin-Eau Claire.

[1] Network industries are characterized by product distribution lines connected by nodes that serve multiple distribution lines. Examples include electric and gas utilities, pipelines, telecommunications companies, railroads, and the U.S. Postal Service.

2 FUNDAMENTALS OF RATE REGULATION

2.1 Concepts in Traditional Regulation

Investor-owned utilities across North America face regulatory oversight vis-à-vis revenue recovery. Electric utilities and other network firms have traditionally operated under "cost-of-service regulation" (COSR), also known as "rate-of-return" regulation, in which firms submit an accounting of annual costs (i.e., revenue requirement) in periodic rate filings before their regulatory authority for approval. Rates are then set to recover approved historical accounting costs. Such an approach carries both benefits and drawbacks.

Utility regulation exists primarily because electric utilities, particularly transmission and distribution network operations, face limited competitive market pressures. These industries have high fixed costs and significant economies of scale that make competition impractical or inefficient. Regulation serves as a substitute for market competition by protecting consumers from the price implications of this market power while ensuring reliable service and adequate infrastructure investment.[2] Regulatory frameworks aim to balance the public interest with reasonable returns for utility shareholders, while addressing externalities and public policy objectives that markets might not adequately account for on their own.

Electric utility rates are regulated through a formal rate application process commonly referred to as the "rate case".[3] A rate case is a formal regulatory proceeding where a utility requests approval to change its rates. The process typically begins with the filing of the utility's proposal with supporting documentation, followed by discovery and information exchange between parties. Public hearings provide opportunities for stakeholder input, while expert testimony and cross-examination help establish the factual record. After deliberation, the regulatory commission issues a final decision. These proceedings serve as the primary way for determining what costs are prudent and reasonable for recovery through customer rates, establishing the balance between utility financial health and consumer protection.

A key component of rate cases is the revenue requirement, which serves as the basis for determining rates charged to customers. The revenue requirement in COSR consists of several key components, as shown in Equation 2.1. Return on rate base provides utilities with the opportunity to earn their authorized rate of return on invested capital, while annual capital expenses include depreciation and amortization. Operating expenses include labor, materials, services, and fuel costs necessary to provide service. Various taxes, including income and property taxes, are also factored in, along with other approved costs such as demand-side management programs. The formula is often expressed as:

$$Revenue\ Requirement = Operating\ Expenses + (Rate\ Base * Rate\ of\ Return) \tag{2.1}$$

[2] Walter Adams. *The Role of Competition in the Regulated Industries*, 48 *American Economic Review* 527. 1958.

[3] While "rate case" is the commonly used term in the United States, the name of the process can differ in other jurisdictions. For example, rate cases are called rate determinations in Australia and price control review in the United Kingdom.

This comprehensive approach provides utilities with the opportunity to maintain financial viability while providing essential services.

COSR has several important implications for both utilities and consumers. A benefit of COSR is that it is designed to allow utilities to recover prudently incurred costs and provides a degree of regulatory certainty needed for capital-intensive investments. COSR also operates such that customers only pay rates for costs incurred prudently. However, COSR also has well-known limitations. The COSR model provides limited incentives for cost efficiency since cost increases can be recovered through rate cases that are timed, generally, at the discretion of the utility. If the utility has the ability to recover all prudently incurred costs whenever cost pressures challenge the ability to recover the allowed rate of return, the incentive to find cost efficiencies is reduced relative to an environment with limitations on timing rate cases. Furthermore, these regulatory proceedings can be resource intensive, which is especially costly in an inflationary environment, wherein utilities must file rate applications with greater frequency.

In most jurisdictions, utility management determines when to file rate applications. While rate case frequency varies considerably across regulatory landscapes, recent years have seen an uptick in filings nationwide, primarily driven by mounting capital investment needs and persistent inflationary pressures.[4] Recognizing the substantial administrative burden these proceedings place on both utilities and regulators, many jurisdictions have implemented limited adjustment mechanisms that allow for targeted cost recovery between comprehensive rate cases, creating a more flexible regulatory approach while maintaining appropriate oversight.

An alternative approach, commonly called either incentive regulation or PBR, aims to mitigate the shortcomings of traditional COSR by providing superior economic efficiency incentives and administrative savings. This alternative form of rate regulation has a decades-long history across multiple industries, including telecommunications, railroads, postal services, and oil transmission pipelines, as well as gas and electric distribution utilities.

2.2 Performance-Based Regulation (PBR)

In recent years, various forms of incentive regulation have increasingly drawn the attention of regulators and utilities as a potential means of improving electricity and gas utility efficiencies and reducing regulatory costs. One category of PBR tools, known as Multi-Year Rate Plans, set a predefined trajectory for rates over the course of the PBR rate term.[5] There are several variants of MYRPs. Indexed caps, in the form of either a price or revenue cap, work by limiting price or revenue growth to an inflation rate that is adjusted by a measure of industry productivity growth, thereby introducing competitive market pressures into a market that is largely considered to be dominated by non-competitive firms.[6] At the same time, the cap provides relief

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[4] Lowrey, Dan. *Rate Requests by US Energy Utilities Set Record in 2023 for 3rd Straight Year. S&P Global Market Intelligence*. February 7, 2024.

[5] The PBR rate term is defined as the period of time the PBR plan is active. For instance, the term may last from 2025 to 2029, after which a rebasing period occurs in which rates are again aligned with the utility's cost of service, and a new PBR rate term may begin.

[6] In competitive markets, prices rise at the rate of inflation minus a productivity growth factor. This is often referred to as *I-X* in incentive regulation, where *I* is the rate of inflation and *X* is a measure of productivity growth. Revenue growth is equal to price growth plus output growth, and so a cap on revenue growth in a

from earnings attrition over time by allowing rates to increase by a simple formula and is therefore sometimes called an attrition relief mechanism (ARM). In some cases, the indexed cap applies to a subset of total revenues, rather than the entire company's revenue requirement. Indexed cap plans that apply to a subset of total revenues are sometimes called "hybrid ARMs."

A second set of PBR tools, known as Performance Incentive Mechanisms (PIMs), provide incentives for utilities to produce certain outputs. Regulators may impose PIMs to encourage utilities to direct resources toward achieving certain goals that are not likely to be achieved under traditional regulatory frameworks. PIMs may be more easily added to existing utility remuneration models than indexed caps, as they do not require an overhaul of the entire framework, but instead could be as simple as a financial reward for achieving a performance target. The details of PIMs and indexed caps are explained in more detail in Sections 4 and 5.

Regulatory frameworks are not binary, which makes it difficult to draw a dividing line between "traditional" and "incentive" forms of regulation. PBR plans operate on a spectrum, often incorporating elements of traditional COSR in an attempt to both minimize business risks and maximize benefits to customers. Like an indexed cap that applies only to a subset of utility costs, regulatory frameworks that incorporate both elements of COSR and PBR more generally are sometimes called "hybrid" PBR plans.

Figure 2.1, depicts the spectrum of PBR along two dimensions: input efficiency and output efficiency. The figure shows that traditional cost-of-service regulation (COSR), in which costs and revenues are closely linked by annual rate application filings to set rates based on costs, provides limited input efficiency incentives. However, adding scorecard metrics or PIMs to a traditional COSR framework can strengthen the utility's output incentives. An indexed cap with no cost trackers tends to have the strongest input efficiency incentives. The introduction of PIMs tends to strengthen a framework's output efficiency incentives. Where a given regulatory framework in the real world exists on this spectrum cannot be pinpointed, but all utility regulation frameworks exhibit some level of efficiency along these two axes.

PBR plan may take the form *I-X+G,* where *G* is the growth rate in the utility's outputs. However, in many proceedings, utilities forego the *G* factor and its absence is treated as a customer dividend, or slower revenue growth which acts as a benefit to customers. These formulas are derived in Appendix B and explained throughout the report.

Figure 2.1: Illustration of the Spectrum of PBR

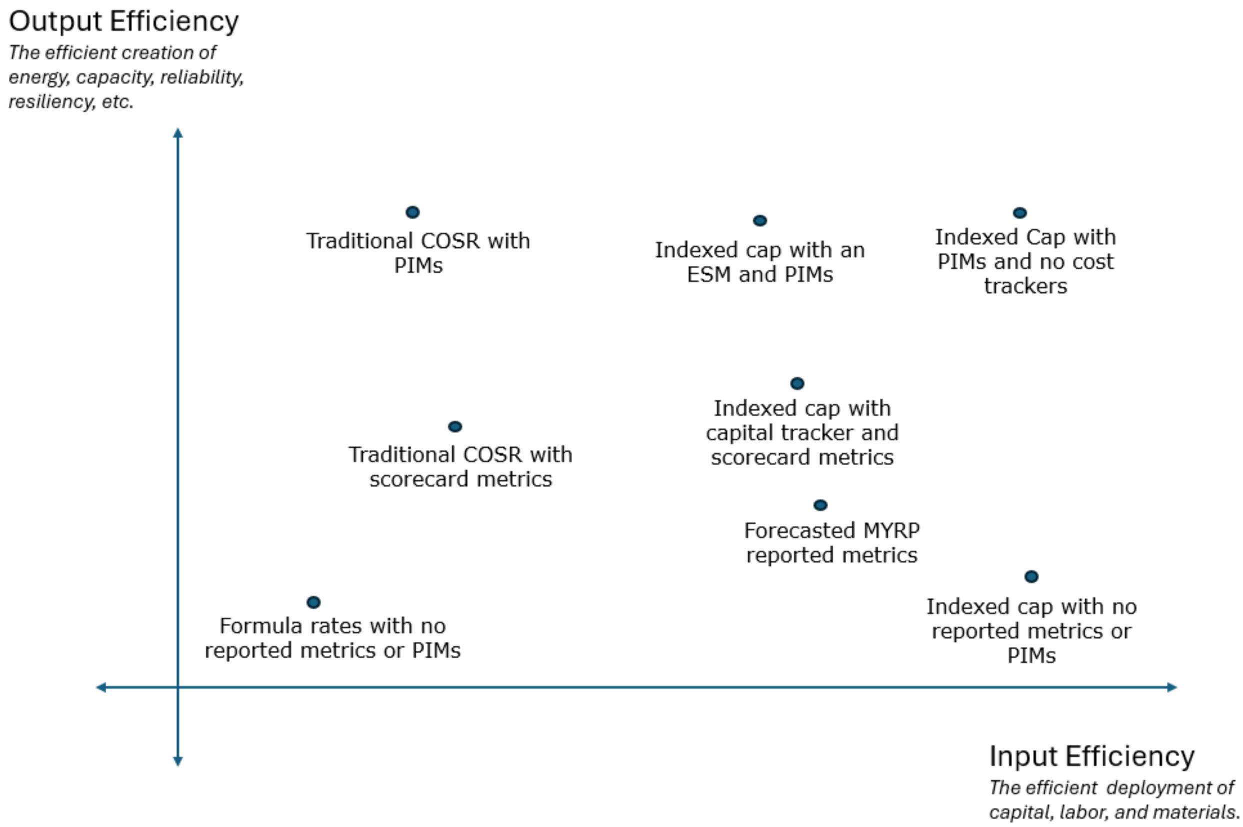
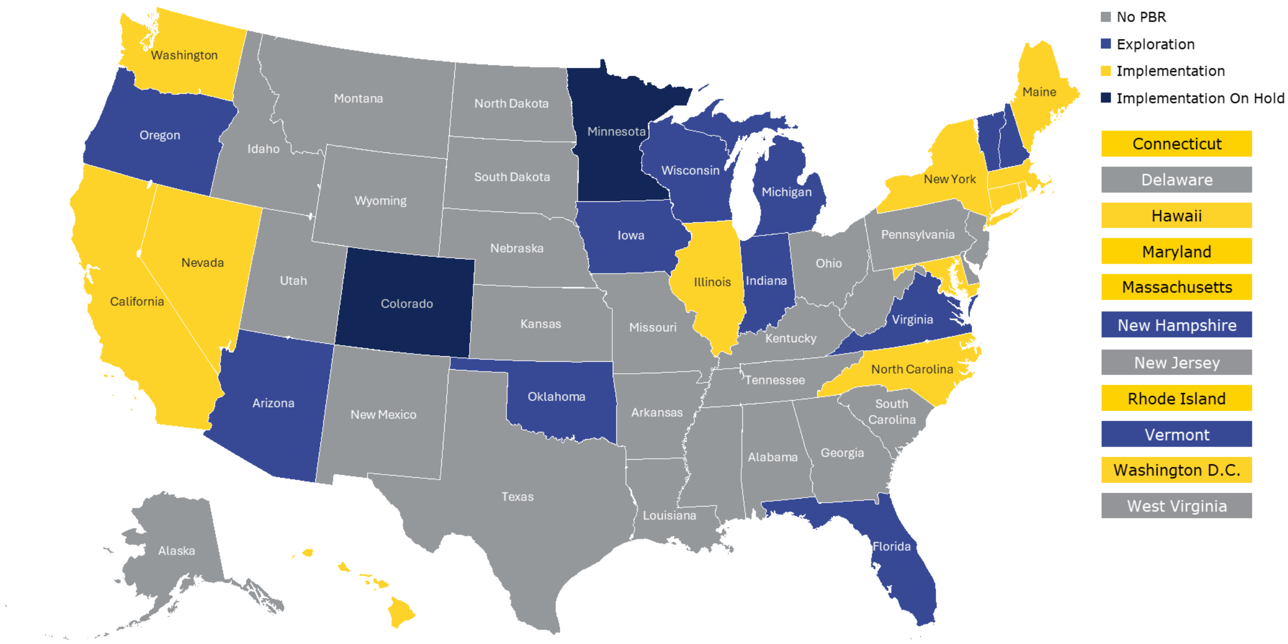


Figure 2.2 provides an overview of PBR development across the United States. PBR frameworks of some kind are also common abroad, in Canada, Europe, Australia, and New Zealand.[7] It includes information on states that are currently exploring or have previously explored PBR. Notably, the state of Maine already operates with elements of PBR, as Maine's existing service quality indicators have PBR incentives. A review of indexed cap (revenue and price cap) PBR plans in North America, Australia, and Great Britain reveals that PBR frameworks differ substantially across jurisdictions. For example, different jurisdictions approach revenue recovery of capital expenditures with different tools. While revenue recovery options for exogenous events are commonly included, the parameters that define them differ between utilities.

Since PBR terminology can vary across different jurisdictions, this figure may not capture every state that has implemented PBR mechanisms. Nevertheless, it serves as a helpful approximation of where PBR has been applied across various U.S. jurisdictions.

[7] Of the 35 European nations surveyed by the Council of European Energy Regulators, all but one regulated its distribution utilities with some form of incentive regulation. See "Regulatory Frameworks for European Energy Networks," Council of European Energy Regulators, February 3, 2025.

Figure 2.2: Status of PBR Across United States[8]



[8] Data for this figure from "Tracking State Developments of Performance-Based Regulation," by National Association of Regulatory Utility Commissioners, April 2024. It has been modified to include other PBR developments CA Energy Consulting is currently aware of.

3 FUNDAMENTALS OF PERFORMANCE-BASED REGULATION

3.1 Introduction to PBR

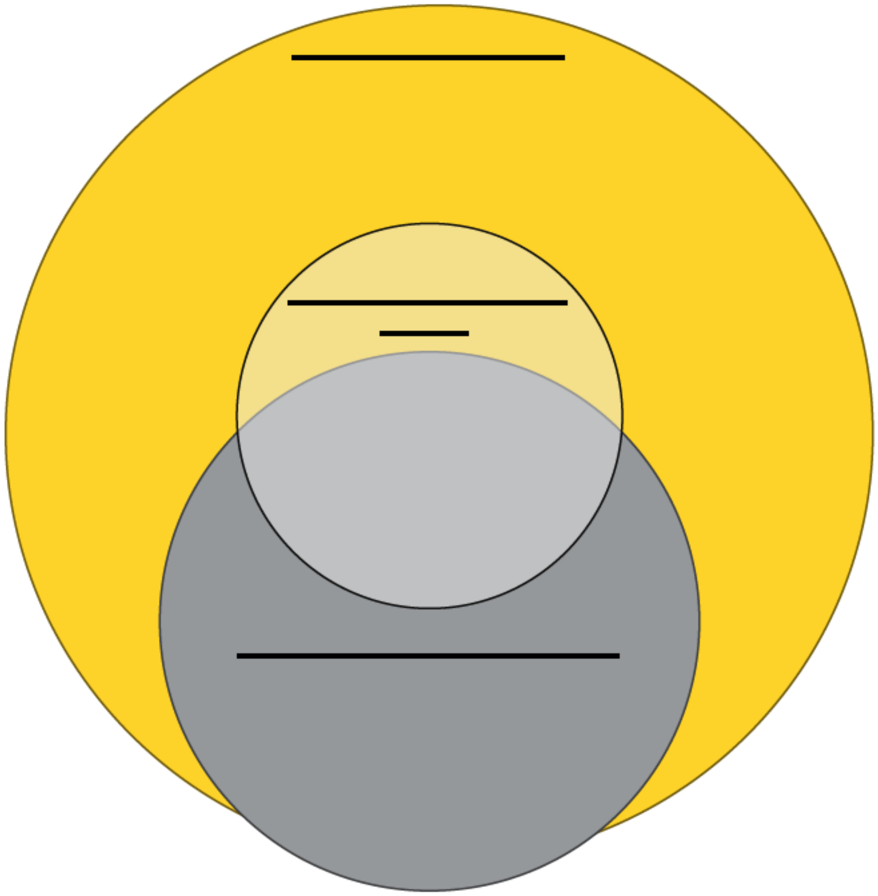
Performance-based regulation is an approach to regulating utilities that emphasizes the achievement of outcomes that benefit ratepayers and utilities through the use of financial incentives. PBR tools may create incentives for cost efficiency, a reduced regulatory burden, enhanced service quality, or the achievement of any number of policy objectives. The principal goal of PBR is to correct for the limitations of traditional regulation and align utility incentives with broader societal goals, such as improving service reliability, promoting affordability, and reducing environmental impact.

As discussed in Section 2.2, PBR can be challenging to define, as it is an umbrella term that refers to a suite of tools that lie along a spectrum of incentive power. The two primary groups of PBR tools are Multi-Year Rate Plans (MYRPs) and PIMs. In general, MYRPs are focused on input efficiency: the aim is to incentivize the utility to produce its outputs using the least-cost combination of inputs like capital, labor, and materials. PIMs, on the other hand, focus on outputs. In an era of energy transition, PIMs may assist with promoting the production of outputs not traditionally required of utilities (for example, DER connections, Electric Vehicle (EV) charging stations, and so-called "non-wires solutions"). These two sets of tools can be used together.

Defining a particular regulatory paradigm as "PBR" is complicated by the details of each regulatory framework. Some long-standing regulatory frameworks already incorporate elements of PBR, even if not explicitly identified as such. For example, service quality indicators like SAIFI and CAIDI in Maine, which include penalties for failing to meet predetermined thresholds, could fit the definition of a PBR tool – in this case, PIMs. The industry acknowledges that PBR is not a binary term, and also that tools that are considered "alternative" to traditional regulation do not necessarily provide enhanced efficiency incentives to utilities.

Figure 3.1 depicts the classification of various alternative regulation tools, which will be defined and discussed in the remainder of this section. The figure shows that some alternative regulation mechanisms, like formula rates, Earnings Sharing Mechanisms (ESMs), and capital trackers are not PBR tools. While the primary PBR tools can generally be placed within the categories of either MYRPs or PIMs, there is a gray area including examples like an MYRP with an ESM, which may have lower-powered incentive properties relative to a price or revenue cap.

Figure 3.1: Categorizing the Tools of PBR



Broadly speaking, when PBR tools are paired with traditional forms of cost-based regulation, financial risk is reduced, but so are the utility's performance incentives. The preferred balance of risk and incentives will depend on the jurisdiction. Likewise, the feasibility of implementing PBR tools, as well as the expected outcomes, will vary by utility. As such, different jurisdictions have implemented PBR in different ways, tailoring their approach to the unique goals and priorities of the utility, the local industry structure, and the policy goals of the jurisdiction.

Subsequent sections of this report provide a discussion of PBR tools currently used in North America. We define terms, discuss benefits and drawbacks, delve into practical applications, and examine how each tool functions within a utility's regulatory framework.

3.2 Guiding Principles of PBR

The design of a regulatory framework should be based on sound economic and public policy principles. Regulators in jurisdictions that have adopted PBR often articulate principles specific to incentive regulation in order to establish a basis for the design and operation of PBR plans. Utilities may rely on these principles when planning rate applications. Stakeholders may want to assess proposed frameworks using these same principles.

If the state of Maine decides to pursue PBR for its electric utilities, we recommend soliciting stakeholder feedback regarding the following principles, which are based on decisions by the

Alberta Utilities Commission[9] and the British Columbia Utilities Commission.[10] These principles are specific to the development of PBR frameworks, and do not supersede or negate other guiding regulatory principles (e.g., the so-called "Bonbright Principles").

> Principle 1: The PBR plan should, to the greatest extent possible, create similar efficiency incentives compared to those experienced in a competitive market while maintaining service quality.
>
> Principle 2: The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> Principle 3: The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.
>
> Principle 4: Customers and the regulated companies should share the benefits of a PBR plan.
>
> Principle 5: The PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

Reaching a consensus on the objectives and design of a PBR plan among industry stakeholders requires time and communication. While the principles above can be considered a useful starting point, industry conditions and preferences in Maine may differ from those in Canada. We encourage stakeholders to provide feedback on this initial recommendation, such that a consensus may be reached. We provide in Appendix C the original list of guiding principles from Alberta and British Columbia, as well as principles from Ontario, Massachusetts, and Hawaii.

Table 3.1 contains a summary of our recommendations regarding guiding principles of PBR for the state of Maine. We find that the seven regulatory goals set forth in the Maine legislature's draft language provide an adequate basis for evaluating regulatory frameworks in Maine.

Table 3.1: Recommendations for Guiding Principles of PBR

Guiding Principles of PBR	*The seven regulatory goals set forth in Section 7.3 stem from the draft legislative language that prompted this investigation. These goals provide an adequate basis for evaluating the regulatory frameworks applied to Maine IOUs, PBR or otherwise.*

[9] Alberta Utilities Commission. *Decision 2012-237*. September 12, 2012. p. 7.

[10] British Columbia Utilities Commission. *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, *Decision and Orders G-165-20 and G-166-20*, June 22, 2020. p. 168.

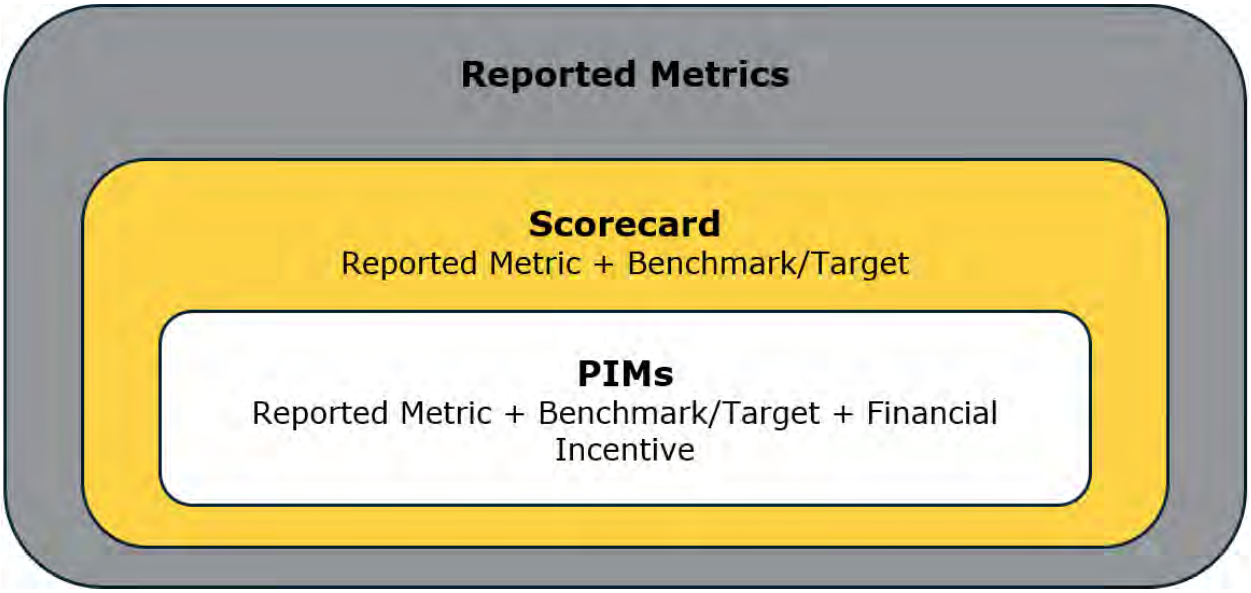
4 PERFORMANCE INCENTIVE MECHANISMS (PIMS)

Performance Incentive Mechanisms (PIMs) constitute the category of PBR tools focused on incentivizing certain utility outputs. These mechanisms are designed to align utility performance with regulatory and public policy goals by providing financial incentives for achieving specific performance targets. PIMs are distinct tools from "reported metrics" and "scorecard metrics," which do not employ financial incentives. Our conclusion is that Maine's regulated utilities currently operate under a set of PIMs (see Section 7.2).

Most utilities publish metrics aimed at providing information on service quality. Utilities, regulators, and other stakeholders benefit from these metrics. Utilities can use performance metrics to better understand areas where improvement or investment is needed. Regulators and other stakeholders benefit through increased transparency into the health of the utility, which can help with establishing policy. The regulator may also better understand certain revenue needs outlined in the utility's rate application if it has insight into the utility's performance history. Deteriorating performance in particular categories might warrant enhanced investment. For customers, scorecards can contextualize the service they receive as individuals within the broader system, which can help with developing sensible consumer advocacy and expectations. These metrics provide a common assessment point between all parties when evaluating utility performance.

As depicted in Figure 4.1, scorecard metrics add a layer of accountability to reported metrics by introducing benchmarks or targets. Establishing such benchmarks can assist with evaluating whether the utility meets its expected service quality. However, scorecard metrics do not involve financial rewards or penalties. PIMs differ from reported metrics and scorecards in the use of financial incentives. For each performance area, regulators establish specific metrics, performance targets, and a system of rewards and penalties. When utilities exceed the established targets, they may earn additional revenue. Conversely, if they fail to meet the targets, they may face financial penalties or reduced returns. Whether a PIM administers penalties or rewards—or both—depends on the design of the PIM.

Figure 4.1: The Hierarchy of Reported Metrics, Scorecards, and PIMs[11]



The subject of performance metrics often arises in discussions of indexed cap or forecasted MYRP frameworks because of a theoretical possibility that the cost-cutting incentives of revenue or price caps will lead to service quality degradation. Metrics can provide counter-pressure to the incentive to cut costs during a PBR stay-out period by providing incentives to maintain superior performance. A performance metric may be focused on preventing poor performance.[12] Although a review of industry literature does not indicate any link between PBR incentives and reduced service quality, performance metrics are seen as a mechanism for monitoring the quality of utility service at the same time that the company faces cost-related efficiency incentives.

4.1 Definition of PIMs

A PIM is an annual revenue adjustment mechanism that ties financial incentives to the achievement of pre-defined benchmarks or targets. PIMs can be reward-only, penalty-only, or symmetric, meaning they could result in both a reward and a penalty. Typically, PIMs operate by adjusting a utility's ROE, though in some cases a pre-determined dollar value is used for a penalty or reward.

To be considered a PIM, the utility must have a measurable target, and it must be possible to recognize the achievement of this target using publicly available information at the end of each year when rates are set for the subsequent year of the PBR term. In addition, the financial penalty or reward associated with achievement of (or failure to achieve) the target must be known in advance. PIM penalties or rewards will be applied to rates each year as a rider, adjusting revenues according to performance in the most recent completed year.

[11] This figure was adapted from: Decision and Order 37507. Hawaii Public Utilities Commission. Docket No. 2018-0088. p. 155.
[12] Whited. *Utility PIMS – A Handbook*. 2015. p. 16.

The Service Quality Indicators (SQIs) currently in place for Maine's utilities are PIMs in all but name. They have a clear performance target that the utilities must maintain and failure to maintain these performance targets results in penalties.

4.2 Considerations for Designing PIMs

A clear set of criteria for the development of PIMs has not been widely adopted across jurisdictions that operate under PBR. However, several jurisdictions have developed principles and guidelines for PIM design. For example, the New York Public Service Commission (NYPSC) offered a useful direction that PIMs should accomplish one of two objectives: (1) encourage achievement of new policy objectives or (2) counter implicit negative incentives that the state's ratemaking model provides.[13]

One question about the design of PIMs is whether to make the financial incentive a reward, a penalty, or financially symmetric — meaning that the PIM offers a reward for positive achievement and a penalty of sub-par achievement. One approach to answering this question is to offer a reward if the utility has not been expected to produce the output in the past, since the cost is not reflected in rates, and a penalty if the utility is expected to provide the output. For example, if a certain level of reliability is expected, a SAIDI or SAIFI PIM could be penalty-only. For new policy objectives, like faster home connections or Non-Wires Solutions, achievement could be tied to reward-only PIMs.

Additional criteria for designing a new PIM may include:

- Does not cause a large increase in administrative burden for utilities, stakeholders, or the regulator;
- Where outcomes align, uses/builds on existing data measured by Maine IOUs;
- Are consistent with/takes into consideration other initiatives on-going in Maine, including existing PIMs;
- Tracks outcomes that utilities can control;
- Have rewards and penalties that are proportionate to the value provided by the achievement of a PIM target (accounting for costs of administering a PIM);
- Are unambiguous, easily interpreted, and objectively verifiable;
- Address policy goals or priorities that are not adequately addressed in existing regulation tools/policies;
- Provide benefits to ratepayers.

These proposed criteria are in line with PIM design principles and guidelines in other jurisdictions such as Rhode Island, Massachusetts and D.C.[14] PIMs need to be evaluated holistically to ensure the metrics do not work at cross purposes with each other.

[13] Interestingly, the NYPSC rejected arguments that PIMs should be restricted to items under the utility's direct control or strong influence, stating that an outcome-oriented approach was the most effective route.

[14] Goldenberg et al. *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals, Rocky Mountain Institute*. p72-75.

PIMs Proposed by National Grid in Rhode Island[15]

In 2018, the Public Utilities Commission of Rhode Island did not accept six out of seven PIMs proposed by Narragansett Electric Company d/b/a National Grid. The Commission evaluated National Grid's PIMs using the following eleven questions:

1. Does the incentive promote the realization of new consumer and societal benefits?
2. Does the incentive promote behavior that the utility otherwise would not take?
3. Is there a clear nexus between the metric and the expected benefits?
4. Is there a clear, stated reason why the incentive is needed to achieve each specific objective?
5. Is the incentive designed to promote superior utility performance and significantly advance the expected benefits as efficiently as possible?
6. Is the incentive designed so that customers receive most of the benefit?
7. Is the incentive designed to grant increasing levels of rewards to the utility for higher levels of performance?
8. Will the design and implementation of the incentive be completely transparent and fully document and reveal inputs and methodologies to ensure no duplication of incentives across various ratepayer funded programs?
9. Is it possible to compare the cost of achieving the metric to the potential benefits?
10. What objectives does this incentive promote?
11. Are these opportunities for the company to earn multiple incentives for attaining the same objective?

For example, the commission rejected the PIM on "CO_2 Electric Vehicle PIM," as the company may already propose a performance incentive that rewards emission reductions within the existing energy efficiency program plan (see Question 2). All six rejected PIMs were approved as track-only metrics with no financial incentive attached.

A question regarding the adoption of PIMs in the state of Maine is whether new PIMs might be imposed on the IOUs, or whether the IOUs may propose their own individual PIMs through a regulatory proceeding. A regulator might impose a standard set of PIMs on utilities in order to achieve a policy objective that utilities might not pursue voluntarily. The drawback, however, is that the same PIM may affect different utilities in different ways. One utility may face conditions that make achievement of certain benchmarks easier than for a utility operating under different conditions. Certain PIMs may cause a proportionally larger administrative burden for small utilities compared to large utilities. Stakeholder engagement can help with evaluating whether a new PIM could be reasonably applied to all utilities in Maine.

Notably, PIMs generally do not aim to address overall utility cost efficiency. This is because PIMs are primarily concerned with the production of utility *outputs*. MYRPs like indexed caps confront the matter of efficient inputs and are therefore better suited for addressing cost efficiency.

[15] Rhode Island Public Utilities Commission. *Report and Order No. 23823 issued to National Grid and the Parties accepting the Amended Settlement Agreement*. p30.

4.3 Challenges to the Implementation of PIMs

There are several issues with providing financial incentives to utilities on the basis of performance metrics. First, utilities operate in a complex macroeconomy which can provoke service quality shocks exogenous to management's control. Penalizing a utility for failing to meet targets due to uncontrollable factors, through a PIM, can render the regulatory framework's incentives ineffective. It is also likely that stakeholders would protest paying financial reward to a utility for achieving goals merely through chance. Policymakers should take care to set PIMs on the basis of metrics that are reasonably within the control of the utility.

Proposed Exclusions from a Reliability PIM

As an example of a PIM design that has attempted to reflect controllable performance, consider the following reliability PIM. This PIM includes six qualifiers to System Average Interruption Duration Index (SAIDI).

In 2024, Public Service Company of New Hampshire d/b/a Eversource, an electric distribution utility in New England, proposed a penalty-only reliability PIM based on SAIDI for its electric operations. For the purpose of calculating a financial penalty for this PIM, Eversource proposed to adjust its SAIDI measure for the following items:

1. Interruptions that are resolved within 5 minutes or less;
2. Private customer outages;
3. Planned outages;
4. Loss of external supply;
5. Public safety directed outages;
6. Major event days.

These adjustments assist with focusing the PIM penalty on reliability shortfalls within the control of management.

Second, incentive pressure from PIMs may operate with a lag, as management learns how to better find efficiencies or as new investments take time to provide intended benefits. For this reason, some metrics may have limited ability to capture management performance efforts. For example, plant additions aimed at improving reliability may take over a year to implement—and thus, a utility may face penalties even after making system upgrades aimed at avoiding such penalties. In such cases, measures observed over longer time horizons may be more suitable.

Third, obtaining reliable performance metrics for the desired outcomes may be challenging. When designing a PIM, a utility's performance on desired outcome needs to be translated to measurable metrics. These metrics should be based on reliable and consistent data. For example, if the metric wants to measure customer satisfaction with a particular service the utility provides, surveys may need to be designed and implemented. The design of survey questions, sampling methodology, and/or sample size are all important factors to ensure the results actually reflect customer satisfaction. The data collection method should be consistent across years to support accurate comparisons. When multiple potential metrics are available for the same outcome, identifying the best metric may require careful analysis, testing, and refinement.

Fourth, performance metrics have costs. As discussed in the previous paragraph, data gathering may involve considerable time and work. Poorly designed metrics may have large data requirements that are not easily fulfilled, leading to inefficiencies and costs that outweigh the benefit of the information they might provide. One of the costs of establishing performance metrics is determining the appropriate thresholds above or below which a utility will be rewarded or penalized, as well as the magnitude of the reward. This may require expert evaluation, and even with such expert evaluation, a fifth challenge is that the proper amount of reward or penalty will likely be an estimate. Measurement error can result in imbalanced or unfair PIMs.

A sixth consideration in the creation of performance metrics is the concept of "single issue regulation." A metric may obfuscate a problem if it misrepresents the intended goal of the metric, or it may give rise to unintended consequences as the utility optimizes to maximize earnings. For example, if a utility creates a single metric to measure customer service quality by recording the average number of minutes a customer waits on the phone, on hold, the company may become very good at answering calls quickly but neglect other avenues of customer communication like website interaction. A crucial point in the construction of a service quality measurement plan is that the scorecard should consider individual elements as well as the mission as a whole. If the utility focuses on each metric in isolation, some metrics may result in competing incentives. On the other hand, too many metrics can lead to a higher regulatory burden that counteracts the PBR framework's efficiency goals.

Whether or not the utility operates under PBR, management and regulators must balance the costs and benefits of performance metrics, lest the utility suffer from an excessive number of goals, or a set of goals that place excessive pressure on the company's operations. Table 4.1 provides an overview of advantages and challenges of PIMs.

Table 4.1: Advantages and Challenges of Performance Incentive Mechanisms

ADVANTAGES	CHALLENGES
Alignment with Public Policy Goals • Facilitates the promotion of prioritized policy goals. • Shifts the focus from capital investment to measurable outcomes.	**Design Complexity** • Present challenges regarding the quantification of performance outcomes and set appropriate rewards/penalties. • Requires the development of measurable, timely metrics.
Improvements in efficiency • Provides incentives to achieve specific performance goals. • Protects against service quality declines while considering economic efficiency.	**Accounting for External Factors** • May not fully account for uncontrollable external factors. • May require more complicated data interpretation that detracts from administrative simplicity.
Flexibility and Transparency • Increases transparency in utility performance through measurable metrics. • Have flexibility to adjust to changing market conditions	**Unintended Consequences** • Can lead to attention toward specific goals to the detriment of service that is not rewarded/penalized. • May create risk of gaming or manipulation by utilities.

4.4 How to Set Reward and Penalty Targets

A PIM administers a reward (or penalty) to the utility for the achievement of (or failure to achieve) certain pre-determined targets. The determination of these targets should be based on economic principles and data. There are three general categories of methods for setting targets: (1) based on the utility's own past performance; (2) based on the utility's performance in comparison to its peers; and (3) based on quotas or levels set by policy. Whether to use a particular one of these methods depends on the type of PIM, data availability, and the details of the policy objectives the PIM aims to address.

Currently, PIMs in Maine are penalty-only. However, PIMs that offer a financial reward could be considered as tools to address new policy objectives, or to incent activities that are not traditional expectations of electric distribution utilities.

4.4.1 Thresholds Based on Utility's Own Past Performance

A utility's own past performance has been used to set PIM benchmarks in other jurisdictions.[16] A utility may set a baseline using average historical performance, perhaps over five or ten years of history. In choosing the measurement period of historical performance, there is a trade-off: a

[16] See, for example, Hawaii.

longer historical time period can help to smooth over noise in the data that may be outside of the utility's control, but older data may not reflect recent performance and changes in the utility's policy environment. A threshold might then be set equal to one or two standard deviations from this average. A threshold set according to mean and variance information assumes that past performance reflects a reasonable range of performance in the future. It also assumes that a penalty or reward is warranted when performance deviates sufficiently from historical average performance. Other adjustments like weather normalization may be applied to the historical average.

One reason for using a utility's own past performance is that cross-company comparisons may not accurately reflect its unique operating conditions. Different utilities operate in different physical environments, are at different stages of their capital cycle, have different systems, and serve different customer mixes. All of these factors may affect the utility's performance relative to its peers. Applying rewards or penalties on the basis of factors like these, which are beyond the control of company management, may not be just and reasonable.

Another advantage of the historical performance approach is it is relatively simple. In contrast, when comparing companies, the PIM threshold may require a regression model or some other means of controlling for factors driving differences between firms. This introduces the possibility of disagreements regarding technical design, as well as data requirements that could be burdensome. Simple historical averages mitigate this problem.

However, using the utility's own data in setting performance thresholds controls for some factors, but not all. Past performance may differ from the future as a result of system changes, even within the same utility. For example, system upgrades might improve reliability and reduce the standard deviation of reliability measures. Conversely, changing climate conditions may reduce reliability relative to the past. Furthermore, if the utility has not collected the necessary data prior to the introduction of the PIM, the company will need to expend resources to introduce new data collection systems.

Another possible shortfall of this approach is that a utility's past performance may be better or worse than peer companies for reasons within management's control, and as a result, this method could set penalty or reward threshold levels above or below what is reasonable. For example, if a utility works hard to maintain a high level of reliability over time, and then a SAIDI PIM is imposed, it may be punished for good historical performance in the form of challenging threshold levels. Similarly, if the utility knows that future PIM thresholds will be based on current performance, management has some ability to manage SAIDI levels for future benefits. In other words, the PIM becomes *endogenous* to company performance, rather than *exogenous.*

4.4.2 Thresholds Based on Comparison to Peers

Setting PIM thresholds in relation to peer companies involves comparing a utility's performance on specific metrics with the average performance of similarly situated peer utilities. For example, a threshold may be set based on the current year's industry average and standard deviation values, rather than the utility's own historical average.

There are several advantages to making comparisons across peer companies. First, thresholds based on cross-sectional peer performance reflect current conditions and the experience of customers served by utilities regionally. Peer-based thresholds may be more relevant because of the use of contemporaneous data, rather than data from five or ten years in the past. Second, if the goal is to provide similar service quality for all customers, regardless of utility-specific conditions, the peer benchmarking approach is a more relevant measure. Third, whereas utility-specific thresholds may involve some endogeneity, peer-based thresholds are strictly exogenous. This means that a utility that performs well over time relative to its peers is not punished for its good performance.

Drawbacks to the peer benchmarking approach include increased complexity and the possibility that benchmarks are not set relative to a utility's operating conditions. Performance benchmarking across utilities requires more data and the use of more technical methods, increasing the complexity and potential administrative burden of the approach.

4.4.3 Thresholds Based on Quotas or Policy

In some cases, industry standards may set PIM thresholds irrespective of utility historical data or sector-wide cross-sectional data. For example, if a regulator has established a goal of connecting new DER customers within a certain number of days, a utility's past performance, or the performance of its peers in making these connections, may not be relevant. In such cases, the regulator may consider data to frame the threshold, even if the data is not explicitly used to calculate a specific threshold value.

This approach may be used because of data limitations. It may also be the case that the regulator deems empirical information less relevant for the purposes of determining thresholds, as the goal is to achieve a set threshold regardless of current or past utility performance. A drawback, however, is that stakeholders may dispute thresholds not based on concrete data.

4.5 Summary of PIMs Concepts

Utility outputs span more dimensions than just kilowatt-hours of electricity. Output dimensions also include reliability, safety, system efficiency (i.e., load factor), connection time, and customer service. Increasingly, outputs also may involve addressing environmental policy goals like DER connections, the incorporation of EV charging stations, and energy efficiency. Utilities may not have a natural incentive to prioritize certain non-traditional outputs, or perhaps stakeholders agree that enhanced attention to traditional outputs is required. PIMs can offer an economically efficient means to achieving objectives or remedying deficiencies by attaching financial incentives to the achievement of pre-defined standards.

Generally, regulators and utilities institute PIMs after identifying specific, targeted policy goals related to utility outputs. This involves establishing metrics, defining achievement thresholds, and setting financial rewards or penalties. The implementation of PIMs requires careful design to ensure they effectively drive desired outcomes without unintended consequences. Key considerations include selecting metrics that are meaningful, measurable, and within the utility's control; setting challenging but achievable targets; and determining the magnitude of financial incentives that will motivate utilities without unduly burdening ratepayers. We have provided criteria in Section 4.2 that can guide the development of successful PIMs.

Whereas transitioning from a traditional form of cost-of-service regulation to an indexed cap may entail substantial changes for the utility, stakeholders, and the regulator, PIMs have the advantage of being relatively compatible with existing utility remuneration frameworks. For example, a company could add a DER connection PIM to its existing framework, change nothing else, and continue its operations with a new performance-based incentive aimed at achieving a policy goal.

The MPUC and the state's IOUs have established a foundation through existing reliability and customer service PIMs (SQIs), which encourage utilities to maintain service standards. Building on this experience, Maine could expand beyond the current SQIs, using PIMs to advance additional policy priorities and innovation. We recommend that the MPUC, the regulated utilities, and stakeholders collaborate to prioritize policy goals that are currently unaddressed by the state's regulatory framework and establish metrics that reflect the achievement of these goals.

Table 4.2: Recommendations for PIMs in Maine

Recommendations for PIMs in Maine	*1. We recommend that the Maine PUC allow the state's IOUs to file new PIMs as part of future rate applications, to be assessed on a case-by-case basis. We recommend using the guidelines provided in Section 4.2 in the design of these PIMs.* *2. We recommend that before instituting any mandatory PIMs or any PIMs that apply to all IOUs, the Maine PUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. We recommend following the criteria set out in Section 4.2 prior to implementing mandatory PIMs.*

4.6 PIMs in Practice

PIMs have played a role in the United States utility sector since the late 1980s, with use in Maine dating back to the 1990s in the form of Service Quality Indicators (SQIs).[17] PIMs in the US were initially designed to provide financial incentives for utilities to invest in energy efficiency programs. In recent years, these tools have gained increased attention for their potential to support state carbon neutrality goals, as well as to enhance system reliability, improve customer service responsiveness, expand outreach initiatives, facilitate the deployment of distributed energy resources (DERs), and promote non-wire alternatives over traditional capital investments, among other objectives.

The history of PIMs in the United States is closely linked to broader shifts in regulatory practices, particularly in the electric utility industry. The introduction of the Public Utility Regulatory Policy Act of 1978 (PURPA) and the Energy Policy Act of 1992 were pivotal, fostering the development of independent power generation.[18] These changes led to the restructuring of utilities with states separating integrated utilities into distinct generation and transmission and distribution entities,

[17] Maine Public Utilities Commission. *Docket No. 2022-0152*. January 20, 2023.

[18] Joskow, Paul L. *The Expansion of Incentive (Performance-Based) Regulation of Electricity Distribution and Transmission in the United States. Review of Industrial Organization* 65.2. 2024. p. 455-503.

allowing independent power providers to operate alongside the existing grid. This shift in regulatory structure set the stage for mechanisms to incentivize utility performance outside of power production.

In recent decades, the responsibility of electric utilities has expanded, particularly with the growing emphasis on reducing carbon emissions. The introduction of PIMs was a response to this evolving landscape, aiming to motivate utilities to achieve goals they might not pursue without external incentives. Initially, PIMs were primary implemented in lines-only utilities, but over time their use has spread to integrated utilities.[19] A notable example is Hawaii where multiple PIMs have been established as part of the state's adoption of a comprehensive PBR framework in 2021.

A key challenge in discussing PIMs across jurisdictions lies in the variety of terms used to describe similar concepts. While the underlying principles of PIMs remain consistent, they may be referred to by different names depending on the jurisdiction. A good example is Maine's SQIs, which function as PIMs in all but name. These indicators measure outcomes such as System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI), and include a prescribed incentive – specifically, a financial penalty for failing to meet predetermined goals. Maine is not alone in using different terminology; SQIs are a common form of PIM, though not always referred to as such. Other examples of PIM terminology differences include New York's Earning Adjustment Mechanisms (EAMs) and Great Britain's Optimization Output Delivery Incentives (ODIs).

Outside of the United States, PIMs have been implemented by all other major English-speaking countries, each adapting the concept to fit their regulatory frameworks and policy goals. These countries include the United Kingdom, Ireland, Australia, New Zealand, and Canada.

Within the United States, the RMI PIM database offers a record of PIMs implemented over the past several years.[20] CA Energy Consulting leveraged this data to identify PIMs related to four key areas of interest for based on Maine's policy objectives: Interconnection, Greenhouse Gas Emissions, Smart Meters, and Affordability and Cost Control. For each category, we further classify the PIMs into three groups: those that are applicable to Maine ("Yes"), those that are applicable in theory ("Maybe"), and those that are not applicable ("No"). A PIM was classified as "Maybe" if it applies to a specific program for that utility that may not exist in Maine, if some aspects are relevant only to vertically integrated utilities, or if it is only tangentially related to Maine's interests. PIMs were classified as "No" if Maine already has a similar PIM, if the PIM is specific to vertically integrated utilities, or if other criteria prevent it from being applicable to Maine. Beyond applicability, we categorize the PIMs based on their incentive structures: penalty-only, symmetrical, or reward-only. The number of PIMs in each group is illustrated in Table 4.3 below.

[19] National Conference of State Legislatures. *Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy.*

[20] RMI PIMs Database

Table 4.3: RMI PIMs Database

PIM Category	Applicability to Maine	Transmission and Distribution: Penalty Only	Transmission and Distribution: Symmetrical	Transmission and Distribution: Reward only	Vertically Integrated: Penalty Only	Vertically Integrated: Symmetrical	Vertically Integrated: Reward only
Inter-connection	Yes	-	2	17	-	1	3
	Maybe	-	-	6	1	1	1
	No	-	-	-	-	1	2
Greenhouse Gas Emissions	Yes	-	3	18	-	-	3
	Maybe	-	-	9	-	-	5
	No	-	-	-	-	1	2
Smart Meters	Yes	-	-	2	-	-	1
	Maybe	-	-	-	-	-	-
	No	-	-	-	-	-	-
Affordability and Cost Control	Yes	-	2	23	-	-	3
	Maybe	-	14	14	-	-	3
	No	-	-	-	-	23	7
Not Relevant	-	-	12	16	4	2	-

The table above shows that the majority of PIMs in RMI's database are either reward-only (66.8%) or symmetrical (30.7%). While this finding is helpful, readers should take some caution that RMI's database may not be comprehensive. As discussed earlier, many SQIs function as PIMs in practice but are not labeled as such, which could lead to their exclusion from databases like this. Nevertheless, the database indicates a preference for some form of upside incentives.

In the following subsections, we further explore PIMs by looking at examples in three states: Illinois, New York, and Hawaii. Each state provides examples of various PIMs that are pertinent to Maine, highlighting different approaches across transmission and distribution utilities (Illinois and New York) and integrated utilities (Hawaii).

4.6.1 PIM Example: Illinois

The state of Illinois offers an example of a jurisdiction where lines-only utilities operate under PIMs that align with Maine's stated policy objectives. For example, Ameren Illinois Company (Ameren) has a demand response PIM, which aims to reduce greenhouse gas emissions, as well as an interconnection timeliness PIM applicable to DER customers.

PIMs have been employed in Illinois since the early 2010s, following the introduction of the Public Act 97-0616 in 2011, otherwise known as the Energy Infrastructure Modernization Act, which mandated PBR in the state.[21] The use of PIMs was further explored and expanded with the enactment of Public Act 102-0062 in 2021.[22] This Act provided the regulatory framework under which PIMs currently operate. As a result, both Ameren and Commonwealth Edison implemented

[21] Tabish, Herman. *Performance-based regulation: Seeking the new utility business model. Utility Drive.* July 23, 2019.

[22] NARUC. *PBR State Working Group. Tracking State Developments of Performance-Based Regulation.* January 2024.

PIMs as a part of their most recent rate plans.[23] A detailed examination of the subset of Ameren's PIMs that may be worth consideration by the MPUC are provided in the table below. Note that the listed PIMs are not comprehensive, as Ameren has additional PIMs, including reliability metrics similar to Maine's SQIs.[24]

Table 4.4: Selected PIMs in Illinois[24]

Category	Example	Details of approved EAMs
Greenhouse Gas Emissions	Peak Load Reduction (2022)	Incents peak load reduction from a demand response program. Metric: MW of peak load reduction. Incentive Structure: Symmetrical Reward: If peak load reduction exceeds 25 MWs relative to a baseline Ameren can start receiving rewards. The maximum reward is +3 basis points with a 50+ MW reduction. Penalty: If peak load is less than 20 MWs relative to a baseline Ameren can start receiving penalties. The maximum penalty is -3 basis points with a 0 or less MW reduction. Status: Active
Affordability and Cost Control	Affordable Customer Delivery Service Costs (2022)	Incents Ameren to introduce proactive measures to decrease arrearages. Metric: Residential disconnections from non-payments in areas of Ameren's service territory with historically high disconnection rates. Incentive Structure: Symmetrical Reward: +3 basis points if target is met Penalty: -3 basis points if target is not met Status: Active
Interconnection	Interconnection (2022)	Incents Ameren to reduce the number of days it takes to interconnect customer DERs. Metric: An interconnection index which is based on the number of days saved in the DER interconnection process. Incentive Structure: Symmetrical Reward: +1.5 basis points if the value is between the performance target and 1.25. +3 basis points if greater than 1.25. Penalty: -1.5 basis points if between .75 and 1 and -3 basis points if less than .75. Status: Active

[23] Illinois Commerce Commission. *Commonwealth Edison Company Docket 22-0067*. September 27, 2022. For Ameren's most recent rate case see the following footnote.

[24] Illinois Commerce Commission. *Ameren Illinois company d/b/a Ameren Illinois Case Docket 22-0063*. September 27, 2022.

4.6.2 PIM Example: New York

Regulated electric utilities in New York operate under a variety of PIMs (known as Earnings Adjustment Mechanisms, or "EAMS") implemented as part of the state's Reforming the Energy Vision (REV) framework. Like the electric utilities in Maine, New York's distributors do not own generation assets. The perspective from New York regarding the design and implementation of PIMs may be relevant to Maine, given similar regulatory goals between both states.

New York utilities have been subject to the Reliability Performance Mechanism (RPM) and the Customer Service Performance Mechanism (CSPI) for many years. These mechanisms were initially created to prevent excessive spending cuts under Multi-Year Rate Plans.[25] The RPM measures distribution system reliability, including criteria such as frequency and duration of outages, remote network monitoring system performance and timely replacement of damaged poles. The CSPI measures the company's customer service quality using a broad number of indices. The utilities face negative revenue adjustments if certain performance thresholds across the RPM and CSPI are not met.

In addition to the state's existing PIMs, the REV framework introduced specific earning opportunities based on utility performance. While the Commission decides the EAM opportunity areas, each utility can propose their own performance incentives within these identified areas. Table 4.5 summarizes a sampling of EAMs that were approved for New York utilities that we believe may be applicable to Maine.

Table 4.5: Selected EAMs in New York[26,27,28,29,30,31]

Category	Example	Details of approved EAMs
Smart Meters	AMI Customer Awareness – Staten Island (Con Edison 2017)	Increase customer awareness of AMI technology, features, and benefits in Staten Island. Metric: Percent of customers aware of AMI benefits, measured through pre-and post-implementation surveys. Incentive Structure: Reward-only Reward: A $250,000 earnings adjustment will be granted if the company meets or exceeds the target awareness. Penalty: None Status: Inactive (Performance Period Concluded)
Greenhouse Gas Emissions	Demand Response	Designed to measure the maximum annual demand reduction resulting from NYSEG's Demand Response program.

[25] New York State Department of Public Service, Staff Report and Proposal. *Reforming the Energy Vision. Case 14-M-0101*. April 24, 2014. p48.

[26] Consolidated Edison Company of New York Case 16-E-0060, 16-G-0061, and 16-E-0196. January 25, 2017.

[27] New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation Case 22-E-0317, 22-G-0318, 22-E-0319, and 22-G-0320 Joint Proposal. October 12, 2023.

[28] Consolidated Edison Company of New York Case 16-E-0060. April 25, 2019.

[29] Niagara Mohawk Power Company d/b/a National Grid Case 20-E-0380. January 20, 2022.

[30] New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation Case 19-E-0378, 19-G-0379, 19-E-0380, and 19-G-0381. November 19, 2020.

[31] Consolidated Edison Company of New York Case 16-E-0064 and 22-G-0065. July 20, 2023.

Category	Example	Details of approved EAMs
	(New York State Electric & Gas 2023)	Metric: Load relief operationally available in a given year, measured above a baseline. Incentive Structure: Reward-only Reward: A maximum of 12 basis points ($2.6 million in RY1, $2.9 million in RY2, and 3.2 million in RY3) Penalty: None Status: Active
	Electric Vehicle CO2 Reduction (Rochester Gas and Electric 2023)	Incentivizes Rochester Gas and Electric to reduce GHG emissions by increasing the adoption of electric vehicles, such as battery EVs and plug-in-hybrid EVs. Metric: Tons of lifetime C02 reduced Incentive Structure: Reward-only Reward: Based on targets met, the company can receive anywhere from $0.3 million to $1.8 million in RY1 and 0.3 million to $2.1 million in RY3. Penalty: None Status: Active
	Targeted GHG Reduction Metric (Con Edison 2019)	Incents Con Edison to reduce GHG by increasing the adoption of various technologies, such as EVs, solar, and heat pumps. Possible ways Con Edison can incentivize customers include creating advantageous rate structures, improving interconnection efficiencies, and providing rebates. Note that this list is not exhaustive. Metric: Avoided metric tons of carbon dioxide Incentive Structure: Reward-only Reward: Based on targets, Con Edison can earn between $2.1 million and $7.6 million. Penalty: None Status: Inactive (Replaced/Revised)
Affordability and Cost Control	Non-Wires Alternatives Incentive (National Grid 2022)	Incents National Grid to pursue non-wires alternatives over traditional infrastructure investments. Metric: The present value of net benefits projected of the NWA project portfolio. Incentive Structure: Reward-only Reward: The incentive is calculated as the sum of two components: 30% of the present value of net benefits from the NWA project and 50% of the difference between the projects initial cost forecast and its actual cost. Penalty: None Status: Active

Category	Example	Details of approved EAMs
	Electric Share the Savings (New York State Electric & Gas 2020)	Lower the unit cost of NYSEG's electric energy efficiency portfolio while increasing energy efficiency savings. Metric: Lifetime annual electric energy efficiency savings (excluding LMI). Incentive Structure: Reward-only Reward: The company retains 30% of gross savings above a baseline target and budget amounts. Penalty: None Status: Inactive (Performance Period Concluded)
	Smart Building Electrification (Con Edison 2023)	Incentivizes greater energy savings from efficiency measures that facilitate a more cost-effective transition to building electrification. Metric: Lifetime energy savings. Incentive Structure: Reward-only Reward: 2.5 to 6 basis points ($4.4 million to $11.8 million) Penalty: None Status: Active
Interconnection	Distributed Energy Resource Utilization (Rochester Gas & Electric 2020)	Incentivizes solar and energy storage interconnection. Metric: Expected annual output from solar and energy storage interconnected within a rate year. Incentive Structure: Reward-only Reward: Up to 10 basis points Penalty: None Status: Active

4.6.3 PIM Example: Hawaii

Utilities in Hawaii are vertically integrated, which presents some applicability challenges for certain PIMs, but there are still valuable lessons to be learned from PIMs they have implemented and their approach to implementation. Hawaii devoted considerable time to researching and consulting various stakeholders to determine the best methods for implementing PIMs. In this section, we focus on PIMs from Hawaii that could be adopted by lines-only electric utilities.

The Hawaiian Electric Companies (HECO) report a broad set of metrics, with dozens of different metrics currently in effect.[32] While many of these metrics are merely reported, rather than PIMs offering financial incentives, the companies also currently operate under eight PIMs. A working group appointed by the PUC assisted with the conceptualization and design of Hawaii's current PIMs. Comments and proposals were also submitted by HECO and several other stakeholders, which the PUC considered in its final decision. Given the energy transition goals underpinning the state's PBR framework, many of the approved PIMs pertain to incorporating renewables and DERs onto the grid.

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[32] Hawaiian Electric. *Performance Scorecards and Metrics.*

HECO's PIMs aim to achieve both energy transition goals and affordability for customers. However, some of the PBR tools employed by HECO apply to generation services, which are not relevant to Maine's IOUs. For example, to accelerate renewable energy adoption, the Renewable Portfolio Standard-Accelerated (RPS-A) PIM rewards utilities for exceeding clean energy goals, incentivizing faster integration of renewable sources like solar and wind.

Other HECO PIMs could be more applicable in Maine. For example, the Interconnection Approval PIM encourages faster approval processes for connecting new renewable energy systems to the grid.

To encourage affordability and equity, the Low-to-Moderate Income Energy Efficiency PIM pushes utilities to collaborate with energy efficiency programs, helping low-income residents participate in the energy transition by offering them ways to manage their energy use and potentially save money.

The HECO companies have had mixed success in meeting its PIMs objectives. In 2022 and 2023, HECO exceeded the PIM connection time threshold for its Interconnection Approval PIM. HECO achieved its renewable generation threshold for the RPS-A PIM in 2022, but not in 2023. None of the three HECO IOUs achieved the SAIFI, Call Center, or AMI Utilization PIMs thresholds in 2022 or 2023. In some cases when PIM thresholds were not achieved, HECO cited forces beyond the Company's control as presenting obstacles to achievement of the PIMs.[33]

Table 4.6 presents HECO's PIMs that are applicable to Maine, describing the metrics, rewards, penalties, and PIM status. Each PIM effects all Hawaiian Electric Company. Note that the list of PIMs is not comprehensive and excludes those less applicable to Main, such as reliability and call center PIMs, which are already in place.

Table 4.6: Selected PIMs in Hawaii[34,35,36]

Category	Example	Details of approved EAMs
Smart Meters	Advanced Metering Infrastructure Utilization (2021)	Incent acceleration of the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs. Metric: Percentage of total customers with advanced meters delivering at least two of the three benefits ("Customer Authorization", "Energy Usage Alert", "Program Participation") Incentive Structure: Reward-only Reward: A minimum reward of, if performance is met, of $1 million and a maximum of $2 million. Penalty: None Status: Inactive (Performance Period Concluded)

[33] Hawaiian Electric Companies. *Notice Transmittal to Update Target Revenue through the Major Project Interim Recovery Adjustment Mechanism, Exceptional Project Recovery Mechanism, and Calculation of 2022 Performance Incentive Mechanism and Shared Savings Mechanism Financial Incentives*. June 1, 2023.
[34] Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37507.*
[35] Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37787.*
[36] Public Utilities Commission of the State of Hawaii. *Docket No. 2013-0141, Decision and Order No. 34514.*

Category	Example	Details of approved EAMs
Affordability and Cost Control	Low-to-Moderate Energy Efficiency (2021)	Incent collaboration between Hawaiian Electric and Hawaii Energy to deliver energy savings for low- and moderate-income customers. Metric: Targets are based on residential hard-to-reach energy savings, peak demand reduction, and affordability program participation. Incentive Structure: Reward-only Reward: Shared savings Penalty: None Status: Inactive (Performance Period Concluded)
Interconnection	Interconnection Approval (2021)	Promotes faster interconnection times for DER systems of less than 100 kW. The company is penalized for underperformance and rewarded for exceptional performance. Metric: The average number of business days to complete all steps in the company's control to interconnect DER systems. Incentive Structure: Symmetrical Reward: Based on tier, for example an average interconnection rate of 24 days in 2022 would reward $350,000 to Hawaiian Electric Company while an average of 18 would reward $1.1 million. Penalty: Based on tier, for example an average interconnection rate of 33 days in 2022 would penalize $105,000 to Hawaiian Electric Company while an average of 39 would penalize $315,000. Status: Active
	Grid Services (2020)	Incent the expeditious acquisition of grid services capabilities from DERs. Metric: kW capacity of grid services acquired Incentive Structure: Reward-only Reward: Companies will receive a one-time award on per kW basis depending on the grid services acquired and the service territory it will serve. Penalty: None Status: Inactive (Performance Period Concluded)

4.6.4 PIM Example: Ontario

While PIM examples from Hawaii can offer some helpful perspective on PIM options and implementation, that state's island systems differ from the industry structure in Maine. This section reviews two PIMs that are currently under consideration in Ontario, a province which, like Maine, contains lines-only utilities operating under an independent system operator, and may therefore be more applicable. The selected examples address two of the four key policy areas of interest to the state: interconnections and greenhouse gas emissions. The table below provides a summary of each PIM, including its design, reward structure, and status.

Two other PIMs, not shown, related to reliability (SAIDI and SAIFI) are also under consideration in the province. Decisions regarding whether to implement these proposed PIMs will be made by the OEB in November 2025.

Table 4.7: Selected PIMs Under Consideration in Ontario[37]

Category	Category & Example	Details of approved EAMs
Greenhouse Gas Emissions	System Utilization (TBD)	This PIM is intended to promote more efficient utilization of the electricity distribution system by offering financial incentives for aligning hourly demand with the system's maximum capacity. Metric: Load factor Incentive Structure: Reward-only Reward: Currently being evaluated Penalty: None Status: Currently under consideration
Interconnection	Efficient DER Connections (TBD)	The PIM's function is to incent the timely connection of DERs. Metric: Interconnection Time Incentive Structure: Reward-only or Symmetrical Reward: Currently being evaluated Penalty: Currently being evaluated Status: Currently under consideration

4.7 Summary of PIMs in Practice

PIMs can be applied to a wide range of policy objectives and utilize diverse incentive structures. Utilities in other jurisdictions have operated under PIMs that address the four key areas of interest for Maine – Interconnection, Greenhous Gas (GHG) Emissions, Smart Meters, and Affordability and Cost Control. For instance, New York's Targeted GHG Reduction Metric provided an incentive to Consolidated Edison Company to reduce GHG emissions by increasing the adoption of technologies such as electric vehicles, solar panels, and heat pumps via measuring metric tons of avoided carbon dioxide. This example illustrates that there are ways to incent a lines-only utility to reduce GHG emissions.

In Illinois, Ameren's demand response PIM incentivizes peak load reductions through demand response programs. This mechanism, designed to reduce strain on the grid during peak hours, aims to lower GHG emissions and also seeks to enhance system reliability. Ameren's interconnection timeliness PIM provides an example of a potential tool that could address Maine's goal of facilitating the integration of DERs. By establishing an interconnection that tracks the number of days saved in the DER interconnection process, Ameren's PIM rewards or penalizes the utility based on performance relative to established benchmarks.

[37] Ontario Energy Board. Docket No. EB-2024-1029. Performance Incentive Mechanisms: Advancing Performance-based Rate Regulation.

Hawaii's regulatory framework placed a heavy emphasis on PIMs, some of which may offer helpful examples for Maine. But, some of the current PIMs in Hawaii apply more readily to integrated utilities than the lines-only IOUs in Maine. One potentially relevant PIM could be Hawaii's Interconnection Approval PIM, which promotes faster DER interconnection times by establishing performance tiers with corresponding rewards and penalties.

PIMs: Vertically Integrated Vs. "Lines-Only" Utilities

In Subsection 4.6, we presented "selected" PIMs that might have applicability to the utilities in Maine, setting aside PIMs designed to influence the generation portion of a utility's operations. In states with vertically integrated utilities, policy goals like Maine's plan to reduce greenhouse gas emissions (see Section 7.3), could warrant the introduction of PIMs to incent a transition to alternative fuel sources for power generation. Maine's utilities do not have the ability to determine the fuel mix of the state's power generation.

Integrated utilities in other states have operated under PIMs aimed at addressing policy goals similar to Maine's, but are not applicable to Maine's regulatory context. For example, Hawaii's RPS-A PIM, which rewards the Hawaiian Electric Company's (HECO) achievement of the State's Renewable Portfolio Standards.[38] This PIM provides a financial incentive for increasing total renewable generation in the HECO system. Central Maine Power (CMP) and Versant Power do not have the ability to make decisions about power generation, so this PIM cannot reasonably be applied in Maine.

Similar PIMs have been applied to vertically integrated utilities in North Carolina and elsewhere. Policymakers and regulators must take care not to assume that a PIM that works well in one jurisdiction can be copied and applied elsewhere, particularly if differences exist in the organization of the industry.

Across all three states examined above, there is a clear tendency to employ reward-only or symmetrical PIMs. This contrasts the SQIs in Maine, which employ penalty-only structures that penalize utilities for failing to meet benchmarks. While downside PIMs aim to provide accountability and protect customers, they are not ideal in all cases and can create cost recovery problems. The diversity of PIM structures across Illinois, New York, Hawaii, and beyond demonstrates the flexibility of PIMs to adapt to different regulatory environments and policy priorities, which may help Maine as it considers expanding the use of PIMs to achieve its own policy goals.

[38] Performance Incentive Mechanism Provision, Hawaiian Electric Company tariff, Effective June 1, 2021.

5 MULTI-YEAR RATE PLANS

Utilities in Maine have the ability to file Multi-Year Rate Plans (MYRPs) under the state's current rules. These "Alternative Rate Plans" can be filed at the discretion of the utility, and, in fact, the MPUC encouraged Versant Power to file a multi-year Alternative Rate Plan in its next rate application.[39] This section explains the benefits and challenges of MYRPs, as well as best practices for implementation. MYRPs can be used together with PIMs. As discussed in Section 4, PIMs can provide counter-pressure to potential cost-cutting that may lead to service quality degradation under a MYRP. Ultimately, we recommend that the MPUC adopt guidelines that help the state's utilities design quality, workable MYRPs.

5.1 Why Pursue MYRPs?

In recent years, capital and operating costs faced by electric utilities in North America have increased at a faster pace than the long-term average.[40] To maintain revenues commensurate with costs in an inflationary environment, utilities will generally propose new rates through a rate application filing before the state or provincial regulator. When cost pressures accelerate, rate applications are likely to become more frequent. This can be problematic because, often, such rate applications are viewed as administratively burdensome and costly.

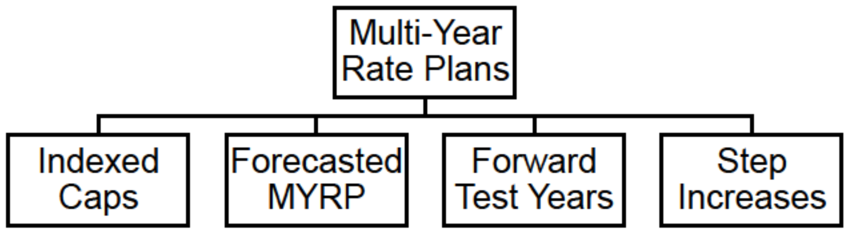
MYRPs are a category of alternative regulation tools that provide a framework for setting rates that can reduce the frequency of utility rate cases, facilitated by rate adjustments that either follow industry cost and productivity trends or align with the company's own costs—actual or forecasted. Thus, rather than establishing static rates that remain in effect until a future rate case—as under traditional COSR—a MYRP sets a schedule or formula that allows rates to change over the plan period. It is not until the end of the MYRP period that rates are reset through a comprehensive cost-based rate case. Most MYRP terms last three to five years.

Figure 5.1 depicts several categories of MYRPs are currently used by utilities in North America. This subsection will discuss the details of two of these forms of MYRP—indexed caps and forecasted MYRPs. The other two, forward test years and step increases, are quite similar to the forecasted MYRP approach, relying on information regarding expected costs.

[39] Maine Public Utilities Commission. *Order: Request for Approval of Distribution Rate Change Pursuant to 35-A M.R.S. 307. Docket No. 2023-00336*. March 13, 2025.

[40] Crowley, Nicholas, and Daniel McLeod. *Trends and drivers of distribution utility costs in the United States: A descriptive analysis from 2008 to 2022. The Electricity Journal.* Volume 37, Issue 3. April 2024.

Figure 5.1: Forms of MYRP



MYRPs have existed for decades in some jurisdictions, but no two MYRPs are exactly alike. Depending on their design, MYRPs can include cost efficiency incentives for the utility, which may yield higher profits to the utility and slower rate escalation to customers.[41] If costs exceed expectations, however, returns may decline, with the impacts to net income associated with cost overruns borne by shareholders. Some, but not all, forms of MYRP may be considered PBR. The nature of a plan's incentives depends on its design. For example, while indexed cap plans like price caps and revenue caps are generally considered to be a fundamental form of PBR, formula rate plans, which adjust rates according to a utility's actual costs, would not be considered a form of PBR. We discuss the different forms of MYRPs in Subsections 5.2-5.4, below.

MYRPs of any kind may also layer into the framework performance incentives and efficiency targets for the utility. The goal with these additional mechanisms is to provide the utility with incentives to find efficient ways to improve service quality or promote policy objectives. We discuss such measures, known as PIMs, in Section 4.

If designed well, MYRPs can benefit both utilities and consumers. Utilities gain more predictable revenues and may obtain stronger incentives for cost control and innovation. Consumers may benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared. However, these plans also carry risks. Customers may need to tolerate that their utility has the potential to earn profits above the allowed rate of return if costs decline over the PBR term. Likewise, utilities may face financial strain if costs rise unexpectedly. As discussed below, regulators may pair MYRPs with other mechanisms like earnings sharing or reopener clauses to mitigate these risks and maintain a balance between utility and consumer interests.

Table 5.1 highlights key advantages and challenges of MYRPs.

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[41] Crowley, Nicholas, and Mark Meitzen. *Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities*. *Utilities Policy*. Volume 72. October 2021.

Table 5.1: Advantages and Challenges of Multi-Year Rate Plans[42]

ADVANTAGES	CHALLENGES
Stable rates and revenue: • Generates relatively predictable revenue during the multi-year rate plan period. • Provides rate stability for consumers.	**Regulatory and intervenor resistance** • May not be comfortable with a change, particularly if it's associated with rate increases. • May require legal changes regarding utility regulation.
Cost Efficiency Incentives • Increases the incentive to find cost efficiencies.	**Data requirements:** • May require detailed revenue requirement forecasts at the account-level.
Reduced regulatory burden • Reduces the frequency of rate applications.	**Rate stay-out periods:** • Restricts rate case frequency.

5.2 Indexed Caps (Price and Revenue Caps)

The state of Maine has some past experience with indexed caps. Central Maine Power (CMP) operated under a price cap, which is a form of indexed cap, until 2013. This form of PBR may be worth revisiting to address goals of cost control and affordability. Maine's utilities are currently permitted to propose an indexed framework as part of a rate application.

Indexed cap MYRPs annually adjust prices or revenues based on a formula of factors beyond the control of the company. This formula, known as the "I-X" formula, sets either prices or revenues such that the utility's costs and allowed revenues are temporarily de-linked. This allows the utility to retain profits beyond its allowed ROE over the plan term if it is able to find cost efficiencies. Only at the end of the plan term are rates reset according to the utility's cost to serve. This process is known as "rebasing." The primary objective of indexed cap regulation is to improve the cost efficiency of the utility, though, indexed caps may also provide other benefits including a reduction in the frequency of rate applications over time.

The I-X formula consists of an inflation factor (I) less industry productivity growth (X). The formula is derived from a fundamental economic principle of market competition, which states that over the long run in perfect competition, the costs and revenues of a firm are equal.[43] This principle, translated into the I-X formula, sets a price or revenue growth trajectory that mimics what would occur in competitive markets. (The derivation of the I-X formula can be found in Appendix C.) Thus, even though utilities do not experience perfect competition for distribution services, for example, the regulatory structure under an indexed cap can provide cost efficiency

[42] See, for example: Kenneth W. Costello. *Multi-year rate plans are better than traditional ratemaking: Not so fast. The Electricity Journal.* April 2023.

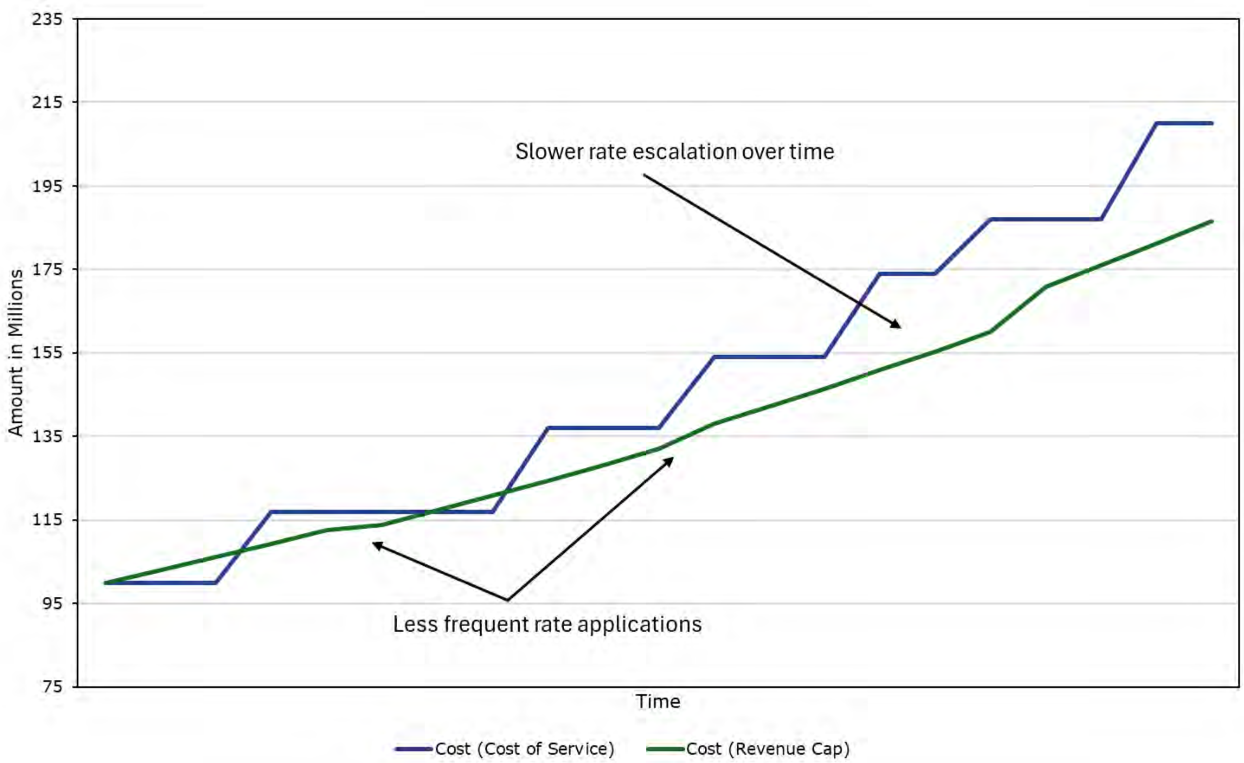
[43] If costs were lower than revenue in the long run, other firms would enter the market and bid down prices such that eventually revenue would equal costs. If costs were higher than revenue in the long run, firms would either leave the market or go bankrupt.

pressures akin to market competition. In contrast, traditional rate-of-return regulation promotes only limited cost efficiency incentives, as cost recovery may be granted on any expenses not disqualified by the regulator.

The power of indexed cap PBR plans to provide cost efficiency incentives lies in the profit motive of the utility. In the short run, the utility may manage to earn above average returns by reducing costs. As costs are reduced, the utility's rates (or revenues) remain stable according to the I-X formula, allowing for higher earnings. At the end of the PBR term, the utility "rebases" rates according to costs. Theoretically, these costs will be lower than they would have been otherwise, as the cost efficiency incentives of the cap will have driven enhanced cost reduction. As a result, the next generation of rates will be lower than they would have been under traditional COSR.

Figure 5.2 provides an illustrative visualization of this concept. As shown in this graph, theory suggests that cost efficiency incentives of indexed caps reduce total utility costs over time relative to traditional cost-of-service regulation. While rates are not immediately reduced, rates are lower over the long term via rate rebasing.

Figure 5.2: How PBR Can Slow Rate Escalation over the Long Term



A resolution to accrue benefits over the long term is necessary for PBR to work properly. As recognized by the Alberta Utilities Commission, under price caps, "customers get the benefit of a more efficient utility and lower cost structures for the same or better utility service over the long term."[44] In the short run, earnings may appear lower or higher what might be experienced

[44] Alberta Utilities Commission. *AUC-Initiated Review Under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Electric and ATCO Gas*. May 24, 2024, p. 25.

under COSR, even while costs decline. If the regulator confiscates higher earnings or provides recovery for underearning through rates, the incentives of indexed caps dissolve. The regulatory economist Dr. Dennis Weisman described this phenomenon as follows:

> "[…]higher than normal earnings may simply reflect the stronger incentives for efficient performance under price cap vis a vis earnings regulation. Should this be the case, these additional earnings would not exist but for the regulator's commitment to allow the regulated firm to be the residual claimant for its realized efficiency gains. In other words, the ability on the part of the regulator to appropriate these earnings may exist only because the firm believed the regulator would not take unfair advantage of this opportunity. It follows that because PCR [price cap regulation] breaks the link between prices and costs, it must also break the link between higher than normal profits and excessive rates […]"[45]

5.2.1 Price Caps

Price caps are a form of indexed cap that limit adjustments to customer rates over a pre-specified period of time. The price cap allows rates and costs to diverge as the utility works to find cost efficiencies to earn superior returns. At the end of the price cap term, typically around five years, the utility files a "rebasing" rate application, resetting rates according to its cost to serve.

Although customer price growth is restricted under this approach, revenues are not restricted. The utility can increase its revenue over the plan term through sales growth. Thus, the utility can improve profits both by increased sales and by cost reduction. Conversely, however, the utility can experience revenue losses, and therefore reduced profits, if sales declines occur and/or if costs increase.

Under a price cap, energy, demand, and customer charge adjustments are made each year of the MYRP term according to an inflation rate minus industry productivity formula, generally called the "I-X" formula. By common practice, the inflation rate is updated each year using government data, while the X factor remains fixed over the plan term.[46] Table 5.2 depicts the mechanics of a price cap. Note that for the Residential customer, both the customer and energy charges are adjusted each year by the percentage obtained from I-X. For the Business customer, the customer, energy, and demand charges are all adjusted by this same percentage.

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[45]Dennis L. Weisman. *Is There Hope' for Price Cap Regulation. Information Economics and Policy, Volume 14(3).* September 2002, pp. 363-364.
[46] The X factor is generally calculated by productivity experts.

Table 5.2: Illustrative Example of a Price Cap

Term Year	I	X	I-X	Residential		Business		
				Customer	Energy (kWh)	Customer	Energy (kWh)	Demand (kW)
Year 1				\$10.00	\$0.080	\$120.00	\$0.080	\$3.000
Year 2	2.00%	-1.50%	3.50%	\$10.35	\$0.083	\$124.20	\$0.083	\$3.105
Year 3	2.10%	-1.50%	3.60%	\$10.72	\$0.086	\$128.67	\$0.086	\$3.217
Year 4	2.00%	-1.50%	3.50%	\$11.10	\$0.089	\$133.17	\$0.089	\$3.329
Year 5	2.50%	-1.50%	4.00%	\$11.54	\$0.092	\$138.50	\$0.092	\$3.463

In most current price (and revenue) cap plans currently in place in North America, the X factor is set equal to zero, even though analysis of industry data indicates negative productivity growth in recent years. Under the assumption of a zero X factor, prices adjust by the rate of inflation.[47] If an empirical X factor that is negative were used to set a price cap, prices would be permitted to rise at a rate slightly above the rate of inflation. This phenomenon correlates to the fact that cost growth across the utility industry has recently exceeded the rate of inflation in the broader economy.

5.2.2 Revenue Caps

Many of the incentive qualities of price caps also apply to revenue caps. As with price caps, both the utility and its customers can obtain benefits through cost efficiencies under a revenue cap if the plan is structured properly. However, some features distinguish revenue caps from price caps.

One difference involves the structure of the PBR formula. Like price caps, revenue caps rely on a formula that includes inflation and productivity growth. However, the revenue cap formula differs from the price cap formula in its inclusion of a growth factor set equal to annual growth in the number of customers. Thus, the formula under a revenue cap sets revenues according to "I-X+G," where G is equal to the annual growth in the number of the utility's customers. This formula is derived in Appendix C.

Another difference involves the utility's operation under revenue decoupling. Revenue decoupling is generally not included in price cap plans. However, most revenue cap plans in North America rely on some form of revenue decoupling to ensure that revenues do not exceed the cap over the PBR term. The I-X+G formula adjusts the utility's allowed revenue each year, and the revenue decoupling mechanism returns to customers any revenue that is collected over the cap (for example, from higher than expected sales volumes). In fact, if a revenue cap operates without a mechanism to return excess revenues to customers, it is effectively a price cap.[48]

A third difference between price and revenue caps pertains to sales risk. For a utility with concerns about falling sales volumes, a revenue cap with revenue decoupling may be preferred because such an approach would provide revenue irrespective of changes to sales volumes. Revenue caps adjust the utility's allowed revenue according to the I-X formula, and revenue

[47] Inflation is generally a weighted average of labor inflation (e.g. "average weekly earnings") and non-labor inflation (e.g., CPI), based on company splits of labor and non-labor operating expenses.
[48] Crowley, Nicholas, and McLeod, Daniel. *Making Sense of Multi-Year Rate Plans*. 2024.

decoupling adjusts rates according to differences between the utility's expected and actual sales. Together, a revenue cap with decoupling provides the utility with revenue adjustments each year of the plan proportional to industry average cost growth regardless of sales. In this way, a revenue cap approach with decoupling (relative to a price cap framework) can reduce risk for a utility concerned about falling demand for electricity, particularly if it recovers some of its fixed costs through an energy charge.

Such an approach does not eliminate risk, however. Under both price caps and revenue caps, the utility faces the risk that its costs could rise faster than the annual adjustment in revenues (or rates). If costs rise faster than revenue adjustments provided by I-X, the utility may need to manage with lower earnings until the end of the PBR term, at which time it can rebase its rates according to costs.

Table 5.3 depicts an illustrative example of a revenue cap. In Year 1, the utility's revenue requirement is set equal to its cost to serve ($1 billion). In each subsequent year of the five-year plan, the allowed revenue is adjusted according to an inflation rate (I), the X factor, which is based on industry productivity, and company-specific growth in the number of customers served (G). The inflation rate is updated each year of the plan, using published government data. The company also updates G using its most recent annual customer count growth rate. As with the price cap formula, the X factor remains fixed over the plan term. The allowed revenue in each year equals the previous year's allowed revenue, adjusted by I-X. A revenue decoupling mechanism can be used to true up realized revenues and allowed revenues each year.

Table 5.3: Illustrative Example of a Revenue Cap[49]

Term Year	I	X	G	I-X+G	Revenue Cap (Millions USD)
Year 1					1,000
Year 2	2.00%	-1.00%	1.25%	4.25%	1,043
Year 3	2.10%	-1.00%	1.00%	4.10%	1,085
Year 4	2.00%	-1.00%	0.75%	3.75%	1,126
Year 5	2.50%	-1.00%	1.00%	4.50%	1,177

5.2.3 Setting the Base Year

Indexed caps operate by escalating a set of prices (or a company's revenue requirement) using cost information filed at the commencement of the PBR term. The revenue requirement used to set initial rates is called the "base year." Because of fluctuating costs year-to-year, the choice of base year can have a substantial influence on a utility's revenues over the PBR term. Furthermore, if the base year does not capture large, planned expenditures that will annually continue during the PBR term, the I-X formula may not provide sufficient revenue enough to meet the firm's cost of service. This problem may prove particularly troublesome for a utility that plans large plant additions during the PBR term, which might give rise to increased depreciation and operating expenses beyond the I-X formula's revenue adjustment mechanism.

The cost elements included in the first year, or base year of the program, may correspond to the cost-of-service test year revenue requirement that is recovered by the first year of new rates. It

[49] Note that the X factor for a revenue cap generally differs from the X factor for a price cap.

may also be the case, however, that the test year and base year are different. When this occurs, the base year, which sets the PBR term's going-in rates, contains adjustments to a test year to better align the base year with actual expenditures expected during the PBR term.

It is important to select a base year that is reflective of expenditures and costs for the utility over the duration of the PBR plan. Choosing a year with unusually low investment that does not reflect investment patterns over the term of the PBR plan can lead to an inability to fully recover the costs of future investments. Choosing a year with an unusually high level of investment that does not reflect investment patterns over the term of the PBR plan can lead to over recovery at the expense of the consumer. Therefore, it is important to choose the appropriate base year, including adjustments if necessary.

5.2.4 Annual PBR Filings

Utilities operating under PBR submit annual filings to communicate rate changes for the coming year associated with a revenue cap or price cap adjustment. The annual review generally includes updates to all relevant elements of the PBR framework:

- *Inflation* – the formula will be updated to use the most recent government inflation numbers for the chosen inflation measure.
- *X factor* – by convention, in most frameworks, the productivity factor, or "X factor," remains static over the PBR term. However, the X factor could be updated each year with the most recent industry data.
- *Stretch Factor* – this mechanism provides immediate benefits to customers, and, like the X factor, generally remains static over the PBR term.
- *Exogenous Factors (Y and Z factors)* – the utility may be allowed to recover additional costs, as explained in subsections below.
- *Capital supplements* – the PBR plan may also include provisions for the recovery of certain capital costs.
- *Earnings sharing* – some PBR frameworks include earnings sharing mechanisms that return a portion of earnings to customers.
- *PIMs* – rates may be adjusted for penalties or rewards based on performance under these pre-defined mechanisms.

The primary purpose of an annual filing under PBR is for the regulated utility to set rates for the forthcoming year. Other elements may also be included in the annual filing, but a streamlined annual review process with fewer components and fewer intervenor questions is more likely to yield the regulatory efficiencies commonly associated with PBR.

5.2.5 Common Elements of Indexed Cap Plans

Indexed price and revenue cap formulas are frequently supplemented with additional elements to address specific challenges faced by regulators or utilities. These include a stretch factor; a string of letter factors: Z, Y, and K factors; and other guardrails. The purpose of these additional elements is to provide benefits to customers, change the risk profile of the PBR plan, and/or to provide revenue support that is required outside of the I-X formula. Indexed caps may also be paired with an ESM (Section 5.2.5.8).

5.2.5.1 The Inflation Factor

The inflation factor is the component of an indexed cap plan that reflects the expected changes in the prices faced by the regulated utility industry. An indexed cap PBR formula should be designed to produce rates that reflect inflationary pressures on input prices, less adjustments for productivity changes, that a company is expected to experience from year to year during the term of the plan. The purpose of the inflation factor is to capture increases in the utility's input prices that are driven by macro-economic forces.[50] In this sense, the inflation factor should account for price changes that are external to the utility's management.

There are two basic approaches to the inflation measure to be used in a PBR plan. The first approach is to use a measure of economy-wide *output* price inflation, such as the Gross Domestic Product Price Index (GDP-PI). This approach is more common among PBR plans in the United States. The second approach, which is more common in Canadian plans, uses some measure of industry *input* price inflation. The Fixed Weighted Index (FWI) of average hourly earnings is a good example of an input price measure of inflation. An input price measure of inflation captures the prices of inputs purchased by the utility, while an output price measure reflects the prices of goods and services purchased by end consumers.[51]

Table 5.4: Recommendations for Inflation Factors

Indexed Cap Inflation Factors	*If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an inflation factor be included in the PBR formula (I-X). The inflation factor should be established to reflect the electric utility sector's annual input price growth. If an output price measure of inflation is used, the X factor must be adjusted accordingly.*

5.2.5.2 The X Factor

The productivity offset, or X factor, is a key element of indexed cap plans. Coupled with the inflation factor in the I-X formula, the X factor is a mechanism designed such that changes in utility revenues reflect the change in industry input prices and the rate of industry productivity growth. Accordingly, combined with the I factor, I−X represents the expected unit cost performance of an average performing company in the industry when productivity is defined with customers as the output measure.[52] Together, the inflation and X factors mimic the pressures of a competitive market by pegging company revenues to its performance in comparison to its peers. To the extent that the firm is more productive than its peers and is able to produce at lower costs, it earns a superior return. Conversely, firms that are less productive than the

[50] Alberta Utilities Commission. *Decision 2012-237*. p. 32.

[51] Using an input price approach simplifies the X factor calculation. If an output price measure were used, the X factor would be modified to include a TFP growth differential between the economy and the utility, as well as an input price differential between the economy and the utility. No such differential is required to set the X factor when using an input price measure of inflation. Instead, the X factor under an input price inflation measure simply equals industry TFP growth.

[52] Where the unit cost equals total cost per customer.

industry average earn lower returns.[53] According to economic principles explained in Appendix C, the use of expected productivity in setting the X factor provides the appropriate level of attrition relief to the regulated firm under an indexed cap.

In some cases, regulators have set the revenue or price cap equal to input price inflation with a zero or arbitrary X factor. However, this is not the correct approach and could cause problems for the utility operating under the cap. The I factor only captures the change in input prices faced by the industry. It does not capture the required change in input *quantities.* A simple example illustrates the problem with this approach. Suppose a utility must replace a large portion of its poles and suppose the price of a single pole does not change from year to year. In this case, the I factor would equal zero, because the input price remains unchanged. If revenue were allowed to increase only by the I factor, the utility's revenue growth from one year to the next would equal 0%. This would be an insufficient revenue increase, because the change in the quantity of poles will increase costs, such that total costs exceed total revenues. Although this is a simplified example, this concept, in essence, is what the X factor represents: industry productivity, or a change in input quantities relative to the change in outputs. By setting the revenue cap with both an empirical inflation measure and an empirical productivity measure, the revenue cap will be set such that utility revenues are allowed to grow with the industry cost growth experience.

Because the I-X formula aims to provide pressure that imitates the competitive market that is external to the regulated firm, the X factor is generally set using industry data, not data specific to the company under the revenue cap. A TFP growth study using a sample of peer companies is typically used to set the appropriate value for the X factor.[54] Another method, known as the Kahn Methodology, provides similar information using financial data—as opposed to "real outputs" measured in TFP growth studies—and is employed in the price cap regulation of U.S. oil pipelines.

Table 5.5: Recommendations for X Factors

Indexed Cap X Factors	*If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an X factor be included in the PBR formula (I-X). This X factor should be calculated on the basis of an industry TFP growth or Kahn Methodology.*

5.2.5.3 Stretch Factors

The primary objective of indexed cap PBR frameworks is to provide the regulated utility with an incentive to seek improvements in cost efficiency during the PBR term. Under an I-X cap and in the absence of any other plan elements, cost efficiency gains are entirely retained as profits to the utility's shareholders until the end of the PBR term, at which time customers would benefit in the form of lower rates (as the revenue requirement is reset based on a cost-of-service rate

[53] William J. Baumol. *Productivity-incentive clauses and rate adjustment for inflation. Public Utilities Fortnightly.* 1982.

[54] If the X factor were to be based on changes in the regulated firm's productivity, price cap regulation would function in similar fashion to cost of service regulation. Jeffrey I. Bernstein and David E.M. Sappington. *Setting the X Factor in Price-Cap Regulation Plans. Journal of Regulatory Economics*, *Vol. 16, 1999*. p. 9.

case). Regulators may prefer that some of these gains in cost efficiency are returned to customers immediately, rather than retained by the utility until the end of the PBR term.[55] A "stretch factor," S, reduces the growth in prices (or revenues) under the PBR term, by incorporating an additional factor in the I-X formula.

For example, the price formula with a stretch factor is:

$$\%\Delta price = I - X - S \tag{5.1}$$

Where S is generally a positive percentage in the range of 0.00% to 0.40%. The regulator subtracts the stretch factor from the I-X cap to reduce the rate of growth in price and share the expected cost reductions with customers. Thus, customers will face price growth slower than what theory suggests would be expected in a competitive market.

A stretch factor will not change the incentives for efficiency—no matter what price the regulator sets, the firm maximizes profits by containing cost and improving efficiency. Instead, setting a stretch factor is a question of distributional fairness of over what time frame consumers are entitled to a portion of firm-specific efficiency gains through lower utility rates.

The academic literature has alluded to a connection between cost benchmarking results and stretch factors.[56] However, in practice, regulators have calibrated stretch factors without support from an empirical cost benchmarking study. More commonly, benchmarking studies have informed the choice of stretch factor, but relies heavily on "regulatory judgement." We recommend that stretch factors use cost benchmarking information, rather than blind judgement, as the data is publicly available via the FERC Form 1.

Table 5.6: Recommendations for Stretch Factors

Indexed Cap Stretch Factors	*If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a stretch factor be included in the formula (I-X-S). This stretch factor should be company-specific informed by an industry cost benchmarking analysis.*

5.2.5.4 Z Factors

Under indexed cap plans, the utility generally agrees not to file rate applications during the term of the plan. This means that companies operating under price caps or revenue caps must manage with a constrained spending envelope over a period that could be five years or longer.

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[55] Another reason cited for introducing a stretch factor is a desire to return a share of reduced regulatory burden to customers. The stretch factor might also serve as a signal to firms and stakeholders of what the regulator expects the firm to do. Some efficiency changes a utility might seek to make could incur more stakeholder opposition from employees or customers if the benefits of those changes do not pass through to customers in a timely fashion. It is also worth noting that omitting a stretch factor might allow the firm to remain "statically inefficient" over the PBR term, continuing to operate at a higher cost level than its peers.

[56] Lowry, M.N., Getachew, L., Hovde, D. *Econometric Benchmarking of Cost Performance: The Case of US Power Distributors*. The Energy Journal 26 (3). 2005. p. 75–92

Most PBR frameworks include provisions to account for costs that may rise during this time for reasons beyond the control of the utility's management.

One type of costs often recovered outside of a price or revenue cap are exogenous events—one-time costs that arise for reasons clearly beyond the utility's control. The mechanism to recover such costs is called a "Z factor."[57] The Z factor allows for an adjustment to a company's revenues to account for a significant financial impact (either positive or negative) of a one-time event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula. Generally, a relevant Z factor event is one that is unknown (and unknowable) to the company at the start of the PBR regime; that has a substantial impact on the company's earnings; and for which both the event and the financial impact of the event on the company's earnings are largely beyond the company's control.[58] Most indexed cap PBR plans set a minimum threshold (i.e., "materiality") for Z factor events, under which costs are not eligible for Z factor recovery.

In Massachusetts, for example, utilities under PBR can recover, through a Z factor, incremental costs resulting from changes in tax laws that uniquely affect the relevant industry; accounting changes unique to the relevant industry; and regulatory, judicial, or legislative changes uniquely affecting the industry.[59] Other examples that might be eligible for recovery through a Z factor are as follows:

- Government policy changes;
- Judicial, legislative, or administrative changes, orders, or directions;
- Major environmental events (e.g., a major seismic event, flood, fire, pandemic);
- Major labor disruption or supply chain event;
- Acts of war, terrorism, or violence;
- Changes in accounting treatment, standards, or policies; and
- Changes in revenue requirements due to regulatory decisions.

Exogenous factors like the Z factor provide guardrails for the PBR framework, to mitigate the risk that major unforeseen events will impact the utility's finances so materially as to potentially inflict damage on customer service quality or the utility's ability to raise capital.

Table 5.7: Recommendations for Z Factors

Z Factors	*If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Z factor be included in the PBR framework. The Z factor should be company-specific and have a materiality threshold roughly in line with thresholds seen in other jurisdictions.*

[57] See, for example: BC Utilities Commission, Decision and Order G-388-21, 51. Also see, Alberta Utilities Commission, Decision 2012-237. p. 108.
[58] Dennis Weisman. *Assessing the Treatment of Capital Expenditures in PBR Plans*. *Fiscal 2020 to Fiscal 2021 Revenue Requirement Application.* Ch. 11. Appendix GG. p. 36.
[59] Massachusetts Department of Public Utilities. *Docket D.P.U. 17-05*. p. 396

5.2.5.5 Y Factors

During the PBR term, portions of a utility's costs may be volatile for reasons other than one-time exogenous events. Ongoing costs, like fuel to power generation, may fluctuate dramatically, such that they diverge from the indexed cap formula but do not meet the criteria for a Z factor.

Y factor costs are those recurring exogenous costs that do not qualify for Z factor treatment and that should be directly recovered from customers or refunded to them. The purpose of Y factors is to allow for separate cost recovery of those costs outside of management's control, and are therefore recovered outside of the price or revenue cap. Y factor costs could either be costs the company is required to pay to a third party (such as the electricity purchases on the open market) or other regulator-approved costs incurred by the company for flow through to customers.[60]

Some jurisdictions use a term other than "Y factor" when referring to flow-through costs, though these plans still include provisions for such costs.[61] In these cases, a different name fulfills the same purpose as Y factors. For example, FortisBC recognizes "flow-through" costs often through variance accounts. These items include depreciation expense, insurance premiums, income and property taxes, interest expense, the cost of energy, and certain forecasted O&M expenses. Variances related to these items are captured in each of the utility's general flow-through deferral accounts. Other revenue requirement variances are also flowed through to rates using specific deferral accounts.[62] The Hawaiian utilities operating under PBR recover costs pertaining to energy costs and purchased power, pension costs, demand-side management costs, renewable energy infrastructure program costs, under "cost trackers," which is a term that is generally synonymous with the term Y factor.

Examples of Y factors explicitly listed by the Alberta Utilities Commission as eligible include system operator fees, farm transmission costs, costs arising from Commission directives, tax changes, municipal fees, load balancing deferral accounts, and production abandonment costs. In Quebec, the Y factor included retirement costs, which have significant volatility, but the Régie determined that the Y factor would not include tax changes, which, if large enough, could be recovered through the Z factor.[63]

Our research indicates that the classification of costs as eligible for Y factor, or flow-through, treatment varies by jurisdiction. To some extent, these differences may arise because of differences in industry structure between different regions. Like the Z factor, Y factors provide stability to the utility during the rate case stay-out period, so that it recovers potentially volatile costs outside of its control without requiring a new rate case.

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[60] See, for example: Alberta Utilities Commission. *Decision 2012-237*. p. 131.

[61] The term does not appear to be used in Ontario, Massachusetts, Hawaii, or by FortisBC.

[62] BC Utilities Commission. *Orders G-165-20* and *G-166-20, 65*.

[63] Régie de l'énergie. *Décision sur l'établissement des modalités du mécanisme de réglementation incitative*. *D-2019-060*. May 16, 2019. p. 53.

Table 5.8: Recommendations for Y Factors

Y Factors	*If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Y factor be included in the PBR framework. The Y factor should be company-specific and the costs eligible for Y factor treatment should be clearly defined at the outset of the PBR term.*

5.2.5.6 K (Capital) Factors

Electric utilities require capital outlays to maintain and grow service in accordance with their obligation to serve customers and, recently, electric utilities across the US have increased capital spending on new technologies to support electrification of the economy. Utility revenue constraints under PBR therefore create concerns with respect to maintaining service. Revenue deficiencies may arise if the indexed cap base year revenue requirement does not reflect capital needs in subsequent years during the PBR term, or if capital expenditures exhibit high variability. As such, PBR frameworks generally contain revenue support for capital expenditures.

Different jurisdictions in which utilities operate under indexed cap PBR plans have different ways of determining what capital should be recovered under a formula and different ways of managing revenue recovery of capital outside of the I-X formula. Because every utility is different and many PBR regimes are still in their early stages, the industry has not settled on best practice approach to recovering capital under PBR frameworks.

Approaches have also differed across time within jurisdictions. For example, the first generation PBR plan for Alberta distribution utilities allowed for capital tracker filings, which generated excessive regulatory processing, leading ultimately to a change in the second generation PBR plan. Similarly, the British Columbia Utilities Commission (BCUC) found that FortisBC, Inc. could not sufficiently recover revenue for capital spending under its 2014-2018 plan, such that capital was removed from formula treatment under the 2018-2022 plan and is now recovered on a forecasted cost-of-service basis.

A lack of homogeneity across jurisdictions and across time suggests two things. First, although supplemental revenue for capital is common across PBR plans, regulators have flexibility in setting the design of capital recovery mechanisms. Second, the success of each capital supplement methodology is not well tested, as most methods have only existed for a short span of time. Where empirical information on the benefits or limitations of each approach is lacking, economic theory can provide guidance.

There are many differing methods of capital cost recovery under PBR. Table 5.9 provides a summary.

Table 5.9: Summary of Capital Recovery Approaches Under PBR

Approach	Jurisdictions	Methodology
Forecasted Capital	British Columbia; Australia	In the PBR proceeding to set initial rates, the utility establishes a forecast of capital spending costs over the PBR term and recovers these costs through rates.
Cost-of-service (capital trackers)	Massachusetts	Massachusetts Electric d/b/a National Grid has the ability to recover capital expenditures using annual cost trackers.
Project-Specific capital trackers	Ontario; Hawaii	Utilities may recover costs for projects that meet certain criteria. Known as the Exceptional Project Recovery Mechanism in Hawaii,[64] and the Incremental Capital Module in Ontario.[65,66]
K-Bar	Massachusetts, Alberta	This approach provides a capital spending envelope based on the utility's own trend in historical capital spending.[67]

The advantage of the Forecasted Capital approach is that utilities receive their expected revenue shortfall for capital expenses, while still maintaining some incentive to contain those expenses. For instance, in British Columbia, the difference between actual and forecasted expenses are subject to an Earnings Sharing Mechanism, meaning that if the utility spends less than the forecast, it is able to retain some of these savings as profit. Additionally, this approach reduces regulatory burden by setting the forecast before the term begins, and leaving any variances between actual and forecasted spending to be handled mechanistically through the ESM rather than through annual cost-of-service proceedings. The primary disadvantage of the Forecasted Capital approach is that it may incentivize the utility to over-forecast capital expenses if it is able to retain any savings as profit. However, tradeoff can be mitigated through prudency reviews before and after the PBR term, or by forecast penalty terms.

A cost-of-service approach to capital expense recovery involving annual capital trackers has the advantage of minimizing financial risk to the utility, which may be essential during a period of transition in which significant capital investment is necessary. Well-designed capital trackers can reduce the regulatory lag for utilities, increase the willingness of utilities to invest in critical

[64] Hawaii Public Utilities Commission. *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism. Decision and Order No. 38451 Docket No. 2021-0086*. p. 62.

[65] Ontario Energy Board. *An Application by Hydro One Networks Inc. for [an order approving distribution rates], EB-2008-0187*. May 13, 2009.

[66] Note, Ontario distribution utilities may also recover capital costs under another mechanism, known as the Advanced Capital Module.

[67] For more information, see here: Alberta Utilities Commission. *Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities, Decision 22394-D01-2018*. February 5, 2018.

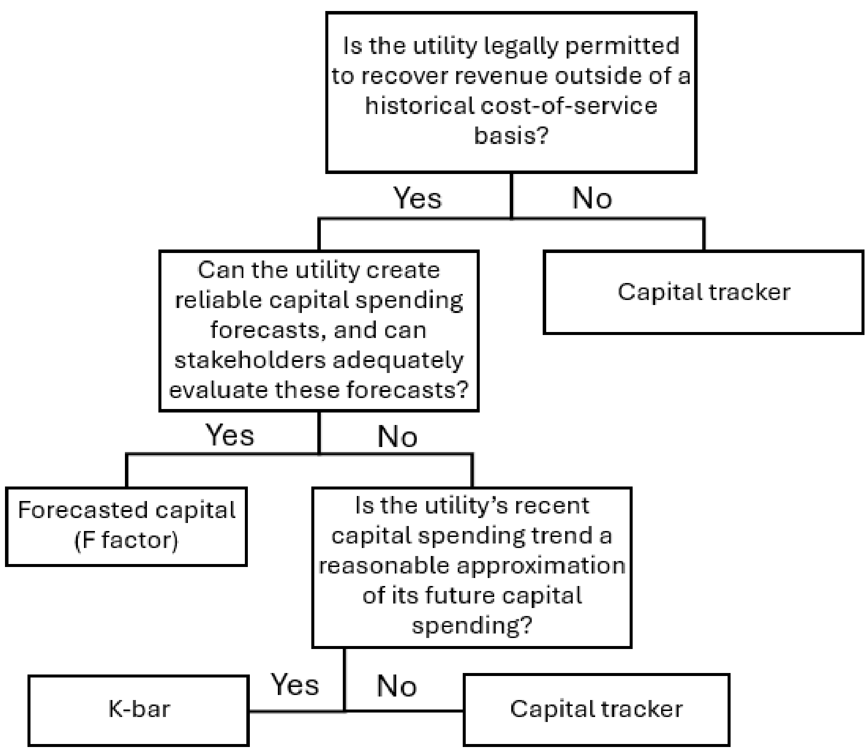
infrastructure. However, capital trackers could also lead to capital over-investment and reduce utilities' incentive to control costs. However, it has the disadvantage of not incentivizing cost containment, which exposes ratepayers to that risk. Furthermore, annual cost-of-service reviews are costly, and run counter to the goals of PBR.

The advantage of the Project-Specific approach is that it recognizes that a cost-of-service is necessary for extraordinary projects whose costs cannot be accurately forecasted, but retains the high-powered incentive structure for the majority of capital spending. The disadvantage of this approach is that it may be insufficient to address capital funding shortfalls more generally, particularly if there is a project-specific materiality threshold that must be reached in order for the utility to apply for project funding, and the utility faces shortfalls on many projects that are beneath this threshold.

K-bar, like the Forecasted Capital approach, has the advantage of retaining the desired cost containment incentives of an effective PBR plan, as the K-bar funding for a given year is determined mechanistically based on investment decisions in the past, as opposed to being tied directly to what is spent in that year. However, K-bar has the disadvantage of being more difficult to understand, and hinges on the assumption that investment decisions in the past are an accurate predictor for investment decisions in the present, which may not hold.

Figure 5.3 presents a flow chart that could be used as a starting point for evaluating what form of capital supplement could work for a given utility. If the utility is not legally permitted to recover capital expenditures prior to placing capital into service, a capital tracker approach may be the only option, even though such an approach has poor cost containment incentives.

Figure 5.3: Evaluating Capital Supplement Options



A review of capital treatment across North American PBR plans revealed that the industry has not reached a consensus on capital recovery under PBR. Each approach to capital recovery gives rise to a certain level of complexity, risk, regulatory burden, and incentive pressure. However, the overarching similarity across PBR frameworks is that utilities have been granted means for recovering additional revenues, beyond what might be permitted under the I-X formula, in order to meet capital spending needs.

Table 5.10: Recommendations for Capital Factors

Capital Factors	*If the Maine IOUs operate under an indexed cap regulatory framework, we recommend that some form of capital supplement be included on an as-needed basis. The capital factor should be company-specific and the costs eligible for capital factor treatment should be clearly defined at the outset of the PBR term. We recommend adopting capital factors that provide cost efficiency incentives, such as a forecasted capital or K-bar approach, when possible.*

5.2.5.7 Reopeners

A fundamental feature of MYRPs is a longer period of time between traditional revenue requirement applications for the utility under the plan. This time between "rebasing" results in a prolonged separation of costs and revenues, providing the utility with enhanced efficiency incentives but also enhanced risk. The I-X formula provides some attrition relief for utilities over the PBR term, but because costs and revenues are separated over the PBR term by design, sufficient cost recovery only persists if the utility experiences stable cost escalation in line with the formula. Since the automatic nature of the I-X formula does not adjust annual revenues for sustained changes in utility costs in the comprehensive manner that rate applications adjust revenues, a utility operating under PBR could potentially experience earnings that are dramatically higher or lower than the amount provided under the I-X formula. To protect against an untenable divergence of costs and collected revenues, PBR plans include "reopeners," or mechanisms that allow for review of the regulated entity's PBR plan during the PBR term and potential relief in the form of adjustments to the PBR plan or exiting the plan completely in the event certain predefined conditions occur.

Reopeners are a common feature of PBR frameworks in North America. It is generally understood that depending on the findings of the regulator, triggering a reopener could result in modifications to a utility's existing PBR plan, termination of the plan, or continuation of the plan. If a problem with the PBR framework is identified, possible remedies to a reopener might include the following:

- Fix design issues – For example, the inflation factor that adjusts rates in Alberta consists of a weighted average of a Fixed Weighted Index (FWI) for labor, and the province's Consumer Price Index (CPI). If the FWI were to deviate dramatically from the price of labor experienced by Alberta distributors, the inflation factor may need to be fixed before the end of the PBR term. Another example would be if a capital supplement were initially critical to providing funding support for necessary investments, but is no longer appropriate for some reason, the reopener could modify this revenue adjustment parameter on a going-forward basis.

- Provide solutions to operational problems – If the utility responds to cost efficiency incentives by reducing costs in a manner that causes concerns for the regulator, targeted solutions like PIMs could be added to provide incentives for the utility to spend efficiently to ensure that service quality does not decline.
- Rebase for unexpected costs – Costs may rise on a broad scale. Likewise, broad-based cost declines may occur. In such cases, rate rebasing may be appropriate and be conducted on a going-forward basis.
- Fix billing errors – If the utility collected revenue that was not correct—for example, because of billing errors, this revenue would be refunded to customers.
- Facilitate an off-ramp – If the PBR framework is found to be fundamentally flawed such that it cannot be modified and continued, an off-ramp allows the utility to leave PBR and transition back to traditional cost-of-service regulation.

Table 5.11: Recommendations for Reopeners

Reopeners	*If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, we recommend that some form of reopener be included. The reopener provision should have a clearly defined trigger and a clear description of how the mechanism would be applied in the event of being triggered.*

5.2.5.8 Earnings Sharing Mechanisms

Earnings Sharing Mechanisms (ESMs) manage the risk of a utility over- or under-earning relative to its allowed ROE. Utilities operating with ESMs share earnings that exceed (or fall short of) a predetermined threshold, either reducing rates for customers in the case of overearning or, depending on the design, providing financial relief to utilities in the event of underearning. As shown in Figure 3.1, above, ESMs are a form of alternative regulation distinct from PBR. This is because ESMs relink the utility's revenues and costs, removing or mitigating cost efficiency incentives. However, ESM are often included in PBR plans as a means of managing risk.

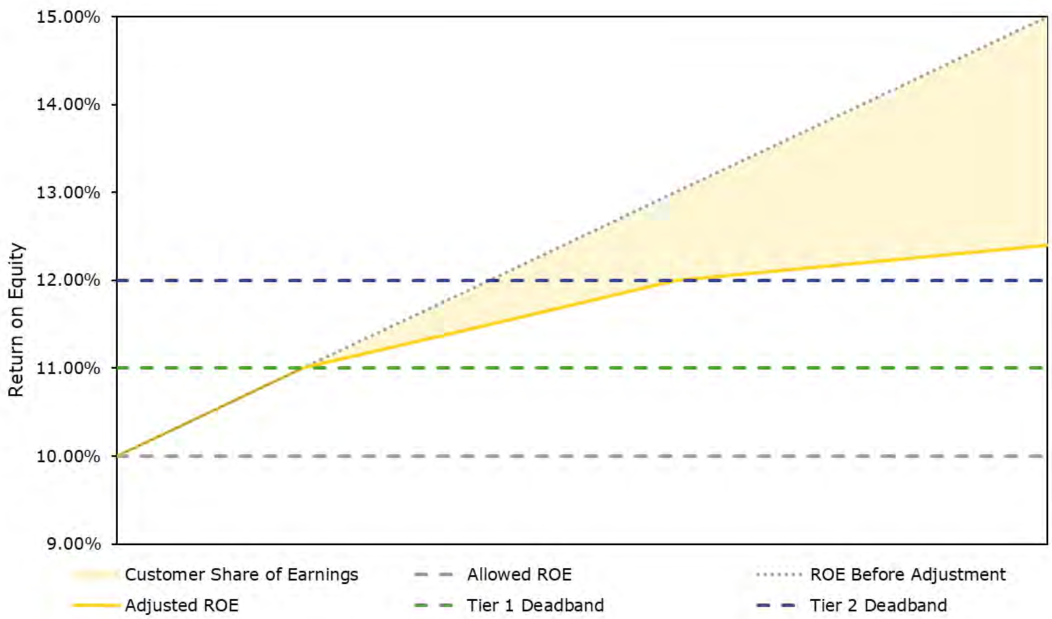
Under both traditional and performance-based regulation, regulators establish a target ROE for the utility through the rate application process. In subsequent years, rates are set according to a revenue requirement that includes this authorized return. Under a symmetrical ESM, if actual earnings exceed or fall short of the target ROE, some proportion of the excess or shortfall is shared between the utility and its customers according to a predetermined formula. This sharing can be structured in tiers, with different sharing percentages applied depending on the magnitude of the deviation of realized earnings from the target or allowed ROE.

A key feature of many ESMs is the use of so-called "deadbands." A deadband is the range around the target ROE within which no sharing occurs. Earnings within the deadband are retained entirely by the utility, insulating it from small fluctuations while maintaining the sharing mechanism for larger deviations. When earnings fall outside the deadband, the sharing arrangement is triggered. If a regulatory framework contained an ESM with no deadband, the utility would operate under pure cost-of-service regulation, with no incentive to find cost efficiencies.

ESMs may have a symmetrical or asymmetrical design. Symmetrical ESMs allow a true-up for both under-and over-earning. Asymmetrical ESMs require the utility to share profits exceeding a predetermined threshold with customers, while bearing full responsibility for any earnings shortfalls. Such a design aims to benefit ratepayers by allowing them to participate in efficiency gains without bearing the risk of earnings shortfalls.

Figure 5.4 provides an illustrative example of how a utility's earnings would change under a two-tier, asymmetric ESM. This example assumes that the utility's allowed ROE is set at 10%. The ESM is structured to have a 100-basis point deadband, such that there no sharing occurs for earnings below an ROE of 11%. If ROE exceeds 11%, the utility shares 50% of its earnings between 11% and 12% ROE and 80% of earnings above 12% ROE.[68]

Figure 5.4: Two-Tier ESM Over-Earning Example



[68] In this example the deadband is established around the adjusted ROE and not the ROE before the adjustment. This is due to the fact that first tier adjustments reduce utilities effective ROE.

Earnings Sharing Mechanisms Example: Eversource Energy

As part of their most recent revenue cap plan, Eversource Energy, an electricity distribution utility, proposed a tiered asymmetric ESM, structure as follows:

- Customers would receive 25% of earnings between 100 and 150 basis points above the authorized ROE.
- Customers would receive 50% of earnings between 150 and 200 basis points above the authorized ROE.
- Customers would receive 75% of earnings exceeding 200 basis points above the authorized ROE.
- No adjustments would be made for earnings below the authorized ROE.

One advantage of this tiered approach, which allows the utility to retain a larger proportion of its earnings just above the allowed ROE, is to facilitate the enhanced cost efficiency incentives of the revenue cap plan while offering protection to customers in case the utility manages to make very large efficiency gains. However, the Massachusetts Department of Public Utilities approved a different ESM, under which customers would receive 75% of all earnings exceeding 100 basis points above the authorized ROE.[69]

ESMs present a good example of an alternative regulation tool that is used to adjust the risk-reward balance of a regulatory framework. While the use of an ESM can reduce earnings risk for the utility and protect customers from paying rates that lead to unpalatable utility profits, the reconnection of revenues and costs also reduces the incentive power of a PBR plan. Through an ESM refund mechanism, utility customers may end up with a bigger slice of a smaller pie in the long run.

Table 5.12: Recommendations for Earnings Sharing Mechanisms

Earnings Sharing Mechanisms	*If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, utilities or utility stakeholders may wish to incorporate ESMs. ESMs are not necessary elements of a regulatory framework. However, if ESMs are adopted, we recommend wide deadbands in order to maintain cost efficiency incentives. For example, sharing only after a 200+ basis point deviation from allowed ROE.*

5.2.5.9 Efficiency Carryover Mechanisms (ECMs)

An ECM is a mechanism that allows for a portion of productivity gains to be kept by the utility beyond the end of a PBR term.[70,71] Over the course of a PBR term, the utility has an incentive to find efficiency gains, but rebasing between PBR generations appropriates these gains (and

[69] Massachusetts Department of Public Utilities. *D.P.U. 22-22*. November 30, 2022

[70] Not all PBR frameworks include ECMs. For example, the revenue cap plans currently in effect in Massachusetts and Hawaii do not have defined ECMs. While the current FortisBC PBR plan does not contain an ECM, the BCUC has allowed FortisBC to apply for an ECM under a certain set of criteria.

[71] Mark Lowry, Matt Makos, J Deason, and L Schwartz, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities. GRID Modernization Laboratory Consortium U.S. Department of Energy*. July 2017.

returns them to consumers) with an updated cost-based revenue requirement. This weakens incentives for the utility to identify and implement efficiency gains in the final years of a PBR term. An ECM is designed to combat these adverse incentives.

Currently, ECMs are not widely used in North American PBR plans.[72] However, theory suggests that economic benefits may be fostered by ECMs. If Maine opts to pursue indexed cap PBR, stakeholders should carefully consider possible ECM designs.

Table 5.13: Recommendations for Efficiency Carryover Mechanisms

Efficiency Carryover Mechanisms	*If the Maine IOUs operate under a MYRP regulatory framework, we recommend consideration of Efficiency Carryover Mechanisms as a way to maintain cost efficiency incentives over rebasing periods.*

5.2.6 Indexed Cap Summary

The indexed cap form of incentive regulation may provide benefits to customers in the form of slower rate escalation over time relative to more traditional regulatory structures that do not provide such cost efficiency incentives. Given current pressures on utilities as a result of price inflation, price and revenue caps could provide Maine IOUs with a tool to address customer concerns regarding cost control.

As discussed above, price caps and revenue caps differ in a few important ways. Under a price cap, revenues vary with consumption, which may lead to increased risks from a business perspective. Over the course of a Multi-Year Rate Plan, a price cap may lead prices to become misaligned with costs to serve if consumption declines, leading to losses that impede future investment. Conversely, consumption increases (e.g., because of sales volume growth) can lead to returns beyond the conventionally acceptable range set forth by the regulating body if prices are not set equal to unit costs. A revenue cap model, on the other hand, allows the utility to adjust its rates to reflect an indexed level of revenue, rather than prices.

Whether conditions in Maine are better suited to a price cap or revenue cap is an open question. Uncertainty lingers with respect to future electricity usage trends because electrification efforts increase the demand for energy even as conservation reduces the demand for energy. Electrification also drives utility costs, creating cost uncertainties. In the face of this uncertainty, revenue caps may provide stability for utilities over the course of the PBR term. On the other hand, revenue caps may limit the revenue growth required to internally fund the investments required to meet electrification demands. The choice between price and revenue caps depends on various factors, including the specific goals of the regulator, the characteristics of the utility and its service territory, and broader policy objectives such as promoting energy efficiency or renewable energy adoption.

[72] ECM was used in Alberta but was discontinued in their most recent PBR plan (Decision 27388-D01-2023) due to insufficient evidence that it was achieving the intended purpose of reduced incentive to find efficiencies towards the end of the rate plan. Australia currently implements a form of ECM through efficiency benefits sharing scheme and capital expenditure sharing scheme, and New Zealand – through incremental rolling incentive scheme.

Indexed caps also carry risks, such as the potential for reduced service quality if utilities cut costs too aggressively. To mitigate this, regulators often incorporate quality of service standards and PIMs into the MYRP framework. Other risks include revenue deficiencies over the PBR term, which, because of the rate case stay-out agreement, cannot be remedied in the form of a timely rate case filing. Such financial risks can also be mitigated through the inclusion of additional elements in the PBR framework (Z, Y, and K factors).

Table 5.14 summarizes the common components of indexed cap PBR plans.

Table 5.14: Description of Factors Used in Price and Revenue Caps

Factor	Description
Inflation	The most recent government numbers for the chosen inflation measure.
X Factor	A measure of industry-wide productivity growth.
Stretch factor (Customer dividend)	Adjustment applied to the X factor to share efficiency gains between utility and its customers.
Z factor (Exogenous cost factor)	Allows rate adjustments for unforeseen, non-controllable events such as natural disasters or major regulatory changes.
Y factor	Allows rate adjustments for recurring costs that utilities cannot control such as transmission charges.
K factor	Provides revenue support beyond I-X for capital expenditures.
Reopeners	Allows for remedying potential problems with the PBR plan before the end of the PBR term.
Earnings Sharing Mechanisms	Share earnings that deviate from allowed ROE. Maybe symmetric or asymmetric, with different proportions of sharing and different deadbands.
Efficiency Carryover Mechanism	Strengthens PBR incentives across PBR rebasing periods.

Successful implementation of price or revenue caps can improve the operational efficiency of utilities and generate savings for customers.

Due to the lumpiness of capital, utilities generally require additional revenue support for capital spending. In addition, each utility operates within a different stage of their capital investment cycle, which means some utilities might benefit, while others may struggle, from the capital input trends reflected in the industry productivity factor.[73] While some of the challenges of applying price and revenue caps can be addressed through the exclusion of highly variable cost components from index cap, such exclusions would also risk reducing the benefits that could be derived from an indexed cap approach.

[73] This can be illustrated with a simple example: if the companies that are included in industry productivity calculation have recently undergone heavy capital investments, the estimated X factor would be lower and would benefit companies that are not pursuing any major capital investments in the near future.

Table 5.15: Recommendations for Indexed Caps in Maine

Indexed Caps	*We encourage the Maine IOUs to propose, and the Maine PUC to accept, indexed cap plans rooted in the I-X formula.*

5.2.7 Real World Indexed Cap Examples

To assist with conveying how indexed caps work in the real world, we present three examples: a price cap from Alberta, Canada, a revenue cap from Hawaii, and a hybrid revenue cap from Massachusetts. These jurisdictions have markedly different characteristics. Alberta's PBR framework regulates all distribution-only utilities in the province with the same I-X formula, wherein each utility operates within a landlocked, meshed transmission grid. In Massachusetts, unlike in Alberta, distribution utilities choose operate under a customized revenue cap. The Hawaiian utilities are vertically integrated and operate on islands.

Alberta provides a price cap model that has been refined over multiple PBR iterations. The Massachusetts example demonstrates how capital may be separated from operations and maintenance costs.

5.2.7.1 Price Cap Example: Alberta Electric Distribution Utilities

In 2023 Alberta Utilities Commission (AUC) approved its third generation PBR (PBR3) plan for the 2024 to 2028 period, which maintains price cap regulation for electric distribution utilities. Alberta utilities' allowed change in prices is described by the following formula:

$$\%\Delta P = (I - X) + Y + Z + K^1 + K^2 \tag{5.2}$$

Where:

%ΔP = allowed change in capped price
I = inflation factor
X = productivity factor
Y = recurring flow through items, collected through Y factor rate adjustments
Z = one-time exogenous adjustments
K^1 = Type 1 capital recovered through capital trackers
K^2 = Type 2 capital recovered through K-bar

The X factor is determined based on the results of total factor productivity studies for the electric distribution industry and is further adjusted by a stretch factor.[74] Mechanically, the stretch factor increases the X factor (which reduces the allowed price increases).

AUC has also established asymmetric two-tiered Earnings Sharing Mechanism:

- For earnings between 200 and 400 basis points above the approved return on equity, utilities retain 60% of the excess.

[74] See Jeffrey I. Bernstein and David E.M. Sappington. *Setting the X Factor in Price-Cap Regulation Plans*". *Journal of Regulatory Economics, Vol. 16*. 1999. p. 9.

- For earnings exceeding 400 basis points above the approved return on equity, utilities retain 20% of the excess.

5.2.7.2 Revenue Cap Example: Hawaiian Electric Company (HECO)

The Hawaiian Electric Company operates under a five-year revenue cap plan, based on the following formula:

$$Revenue_t = Revenue_{t-1} * (1 + I - X - CD) + EPRM + Z \quad (5.3)$$

Where:

$Revenue_t$ = allowed revenue in year t
I = inflation, (equal to GDP-PI)
X = productivity index (set equal to zero percent)
CD = consumer dividend (set equal to 0.22 percent)
EPRM = costs allowed to be recovered under the Exceptional Projects Recovery Mechanism
Z = costs associated with exogenous, one-time events

The formula adjusts revenues each year by the percentage change in GDP-PI (the Gross Domestic Product Price Index) minus a pre-determined stretch factor.[75] Each year, depending on circumstances, the utility's allowed revenue may be adjusted by several additional components, including cost trackers, a Z factor, PIMs, and a capital recovery mechanism.

The Hawaiian utilities have cost trackers that allow for the recovery of costs pertaining to fuel and purchased power, pensions, demand-side management, renewable energy infrastructure program. These costs are recovered outside of the allowed revenue that is adjusted by the inflation-based revenue cap. The Z factor provides the utility with an opportunity to review and recover prudently incurred costs that address events beyond the control of the utility.[76]

The PBR framework also contains a provision for additional revenue related to capital expenditures. In particular, the Exceptional Project Recovery Mechanism (EPRM) is a mechanism that allows the utility to file for cost recovery of projects that meet certain criteria. It provides recovery of allowed revenues for the net costs of these approved "Eligible Projects" placed in service during HECO's five-year revenue cap period, provided that cost recovery is not already covered by another effective recovery mechanism.[77] Eligible Projects include infrastructure necessary to connect renewable energy projects, projects that encourage clean energy choices or conservation, utility scale generation and storage, grid modernization, and other similar projects.

[75] Although the PUC referred to HECO's revenue cap as an "I-X" revenue cap because an X factor was considered, the X factor was arbitrarily set to equal zero in the final decision. For this reason, the Hawaii revenue cap is not truly an "I-X" revenue cap, as it does not incorporate industry productivity.

[76] HECO's exogenous costs must exceed a threshold of $4 million to be eligible for Z factor cost recovery. This is equivalent to 0.14% of the company's total allowed revenue.

[77] Hawaii Public Utilities Commission. *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism. Decision and Order No. 38451 Docket No. 2021-0086*. p. 62.

5.2.7.3 Hybrid Revenue Cap Example: National Grid

Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, operated under a total revenue cap formula from 2019 to 2024, similar to the cap adopted by the Hawaiian Electric Company. However, beginning in 2025, the revenue cap was modified to treat O&M and capital expenses separately; an anticipated surge in necessary capital investment, driven in large part by the Electric Sector Modernization Plan for Massachusetts, was expected to leave the company with insufficient revenue during the 2025-2029 period. To resolve this issue, the company proposed bifurcating its revenue requirement into revenue associated with O&M expenses and a capital revenue requirement. The former would be escalated by an index formula each year, while the latter would be recovered from annual capital revenue requirement filings. This proposal was accepted by the Department of Public Utilities in Massachusetts in 2024, with the O&M revenue requirement escalated using the following formula:

$$OM\ Revenue_t = OM\ Revenue_{t-1} * (1 + I - X - CD) + Y + Z \tag{5.4}$$

Where:

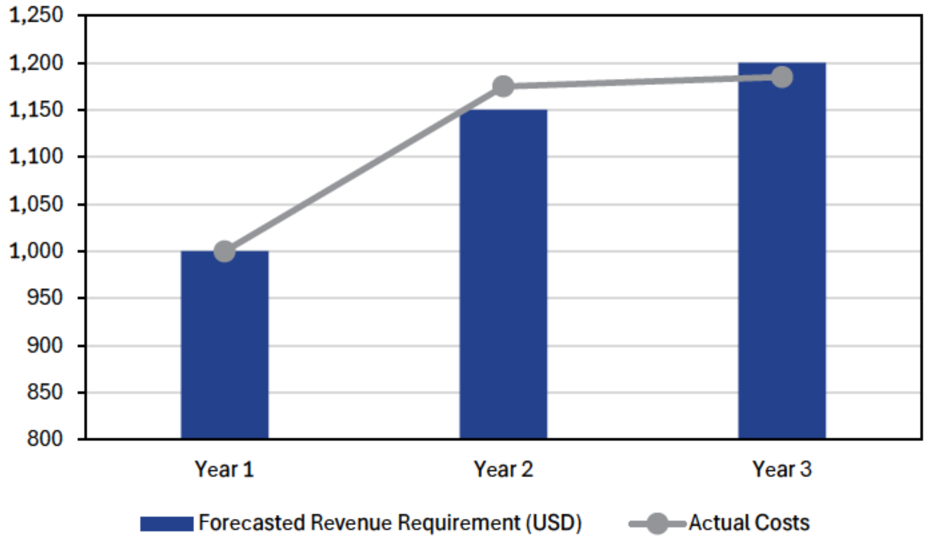
OM Revenue$_t$ = O&M revenue requirement in year t
I = inflation, (equal to a weighted average of a regional employee cost index and the producer price index for electric utilities)
X = partial productivity index (set equal to 0.21 percent)
CD = consumer dividend (set equal to 0.4 percent)
Y = incremental operating expenses arising from increased capital expenditures
Z = costs associated with exogenous, one-time events

5.3 Forecasted Multi-Year Rate Plans

A forecasted approach offers an alternative to the indexed cap MYRP. Utilities might implement a forecasted MYRP in a number of different ways, but the key differentiating feature of forecasted MYRPs relative to indexed caps is that whereas price caps and revenue caps rely on industry average adjustments that are exogenous to the company, a forecasted MYRP relies on the company's own forecasts of its revenue requirement over a period of time. The forecasted MYRP approach establishes the utility's revenue requirement each year of the PBR term at the initial plan filing. These forecasts typically include estimates of future operating expenses, capital investments, depreciation, taxes, and allowed rate of return, as well as projected sales and number of customers served.

Figure 5.5 depicts a prototypical three-year forecasted MYRP. Under this plan, the utility's actual costs may vary year-to-year relative to its forecasted revenue. In Year 1, realized costs are closely aligned with the forecasted revenue requirement. This is expected because forecasts are generally more accurate for costs incurred in the near future than for those further in the future. In Year 2, actual costs exceed the forecasted revenue requirement. In this case, the utility will need to manage under a revenue shortfall, as the revenue requirement cannot be adjusted during the MYRP term. In the final year of the MYRP, the example utility's forecasted revenue exceeds its actual costs. In this case, the utility is able to keep its profits.

Figure 5.5: Illustrative Example of Forecasted MYRP



5.3.1 Advantages of the Forecasted MYRPs

Forecasted MYRPs provide more oversight and control over the utility's revenues during the PBR term, both for the utility and for the regulator, relative to indexed caps. One key advantage of the forecasted revenues approach is that it can provide a more accurate reflection of the utility's expected costs and market conditions compared to indexing caps. This can be particularly beneficial in periods of significant change, such as when major infrastructure investments are planned or when the utility sector is undergoing substantial transformation. A utility facing cost growth substantially different from the rest of the industry might therefore find forecasted MYRPs feasible, even when indexed caps are not workable.

5.3.2 Drawbacks and Risks to Forecasted MYRPs

However, there are risks and potential drawbacks. One drawback is that the forecasting process may involve extensive negotiations, evaluations, and input regarding the projected revenue requirement from various stakeholders, including consumer advocates and industry experts. This process may be more expensive and time consuming than a traditional cost-of-service rate case. However, as with indexed caps, the initial administrative costs would be outweighed by the reduction in rate case frequency and cost efficiency gains under a well-designed plan.

A risk with forecasted MYRPs is that, typically, under a forecasted MYRP, the company may only collect the forecasted revenues—regardless of the costs incurred. While this risk imposes some cost efficiency incentives on the firm, allowing it to earn profits for better-than-expected cost management, the firm could incur losses if its costs exceed allowed revenues. Similarly, companies may seek to benefit from information asymmetry by inflating their forecasted revenue requirement in order to mitigate risk or improve profits. To address concerns that costs may diverge from allowed revenues over the PBR term, regulators often incorporate mechanisms to share the risk of forecast errors between the utility and its customers. For example, in Great Britain, utilities operating under the "Revenue using Incentives to deliver Innovation and Outputs" (RIIO) framework pay a forecasting penalty that increases as actual costs deviate from the forecast.[78] Another approach might include earnings sharing provisions that require the utility to return a portion of any excess earnings to customers if actual costs turn out to be lower than forecasted.[79] Similarly, some plans may include reopener clauses that allow for rate adjustments if actual costs deviate significantly from the forecast.

Another risk, which also exists under indexed cap PBR, is that cost cutting may occur not because of gains in efficiency, but rather, at the expense of service quality. To protect consumers from the utility cutting spending at the expense of service quality or planned capital expenditures, the regulator may introduce PIMs or impose rules requiring capital to be placed into service before related revenues can be collected by the company.

A Note on Future Test Years

A forward-looking test period can be used to set a utility's revenue requirement on the basis of projected data for a 12-month period beginning no later than 24 months after the date on which the utility petitions the commission for a change in its rates and charges. This form of cost-of-service regulation using projected data has qualities that overlap with forecasted MYRPs. Both require forecasted cost information, and both can be used to provide a timely alignment of rates with costs.

As with any regulatory construct, the likelihood of success for forecasted MYRPs depends on the details. The forecast approach also may result in higher or lower cost efficiency incentives depending on the plan design. If the utility can influence the forecast to be overly generous, it may reduce the pressure to cut costs. Conversely, if the forecast is too stringent, it could put undue financial pressure on the utility, potentially compromising service quality or necessary investments.

The forecasted revenues approach can be more complex and resource-intensive than other MYRP methods, requiring significant regulatory oversight and expertise. However, when implemented effectively, it can provide a balanced framework that aligns utility incentives with regulatory objectives while accounting for the specific circumstances and challenges facing the utility over the plan period. Table 5.16 provides our recommendations with regard to forecasted MYRPs.

[78] Decision – RIIO-ED2 Final Determinations Finance Annex, p. 132.

[79] While earnings sharing mechanisms may be effective in addressing forecast errors, they reduce the incentive for utilities to efficiently manage their expenditures.

Table 5.16: Recommendations for Forecasted MYRPs in Maine

Forecasted MYRPs	*We recommend Maine IOUs continue to be permitted to voluntarily file forecasted MYRPs. We further recommend consideration of MYRP terms longer than the two-year plan currently applied to CMP (for example, three or four years). We note that indexed cap plans may offer more simplicity and better cost efficiency incentives, depending on the plan design.* *If three- or four-year forecasted MYRPs are adopted, these plans may include additional elements discussed in Table 8.4. For example, exogenous cost factors (Z and Y factors) may be included, as well as reopener provisions.*

5.3.3 Real World Forecasted MYRP Example: Duke Energy Carolinas

On October 13, 2021, a bill authorizing PBR for electric utilities was signed into law by the Governor of North Carolina.[80] This change permits utilities in North Carolina to submit PBR applications as part of their general rate case. Such applications could include revenue decoupling mechanisms, PIMs, earnings sharing mechanisms, and forecasted MYRPs.

Duke Energy Carolinas' (DEC) most recent general rate case included a PBR plan with many of these elements. DEC proposed and currently operates under a three-year forecasted MYRP with an asymmetric ESM that distributes all earnings excess of 50 basis points above the authorized return on equity to customers. The plan also contains a reopener, which states that if DEC's weather-normalized earnings fall 50 basis points below the authorized rate of return on equity, DEC may file a rate case, thereby leaving the MYRP. Revenue increases during the MYRP are determined based on forecasted capital spending throughout the rate period and are capped at 4% of the first-year revenue requirement, excluding capital spending projects placed in service during the first rate year.

Arguably, North Carolina's approach to MYRPs offers some cost containment incentives. The reopener and ESM limits the benefits utilities can derive from efficient cost reductions. However, the plan may also facilitate other benefits, such as less frequent rate applications and timely cost recovery.

5.4 Formula Rates

We include formula rates in this discussion for the sake of completeness as an alternative form of regulation, but formula rate plans are not considered to be a form of PBR. Formula rates are used by many electricity transmission companies that file rates with the Federal Energy Regulatory Commission, as well as some retail utilities in the southeastern United States.

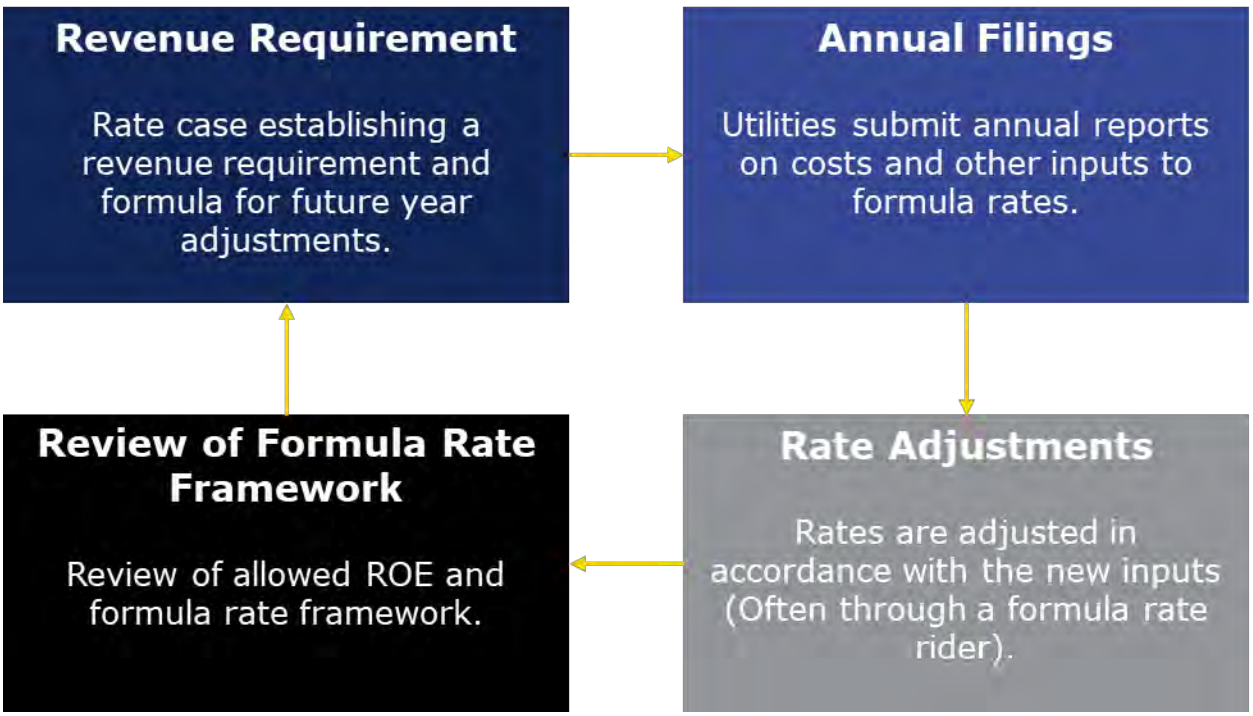
Formula rate plans establish a formula based on company earnings information to automatically adjust rates, typically on an annual basis. Because of the name, formula rates might be confused

[80] *G.S. 62-133.16*

with indexed cap plans, which also rely on a formula. However, the two forms of regulation are very different. Unlike indexed caps, formula rate plans set prices based on company specific data rather than industry-wide information. This means that rates are set on a cost-to-serve basis and do not have the incentive properties of indexed caps. In fact, because of the low efficiency incentives associated with formula rate plans, such plans are not considered to be a PBR tool.

Figure 5.6 provides a simplified overview of how formula rates are established, reviewed and updated. The specifics of formula rates differ between jurisdictions, but the formula rates are generally established for multiple years and require annual filings by the utilities to report their costs and earnings. At the end of the pre-determined formula rate period, the formula rate framework is reviewed and updated.

Figure 5.6: Simplified Formula Rate Application Process



5.4.1 Advantages of Formula Rate Plans

The advantage of formula rate plans is that they are designed to provide a transparent and predictable way to update rates without the need for frequent, full-scale rate cases. The formula usually incorporates various components of the utility's costs, such as operating expenses, capital investments, return on equity, and sometimes performance metrics, as well as allowed rate of return. Each component of the formula is clearly defined and may be subject to specific rules or limits. For example, the allowed rate of return might be adjusted annually based on changes in financial market conditions. Formula rate plans also have the advantage of providing timely cost recovery for utilities. As actual costs change, rates can be adjusted relatively quickly, reducing regulatory lag and potentially lowering the utility's financial risk.

5.4.2 Drawbacks of Formula Rate Plans

One of primary drawbacks of formula rates is that they often allow utilities to pass increased costs directly to customers. This mechanism reduces the utility's incentive to pursue cost reductions or efficiency improvements. It also may make it more difficult to assess projects that are recovered through rates between rate applications. As such, formula rate plans require careful design and ongoing monitoring to ensure they serve the interests of both the utility and its customers throughout the MYRP period.

Table 5.17 provides our recommendations regarding formula rate plans.

Table 5.17: Recommendations for Formula Rate Plans in Maine

Formula Rate Plans	*We do not currently recommend that Maine IOUs pursue formula rate plans. However, if IOUs face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered.*

5.4.3 Real World Example of a Formula Rate Plan: Entergy Louisiana

Entergy Louisiana's rates have been set through a Formula Rate Plan (FRP) since 1995. In Entergy Louisiana's most recent rate case, the formula rate plan has been extended for 2024-2026 period.[81]

Entergy Louisiana operates their formula rates through a FRP Rider. The FRP regulates electric rates by establishing an approved Evaluation Period Cost of Equity (EPCOE) and then requiring prospective rate changes if Entergy Louisiana's test year operating revenues produce an earned return on equity either higher or lower than the approved EPCOE plus or minus a 40-basis point earnings bandwidth (deadband). For a given year of the FRP, if the Company's earned return on equity falls outside the deadband, the FRP will adjust rates to the edge of the deadband.

Each year Entergy Louisiana is required file an FRP evaluation report, which is based on Entergy Louisiana's actual earnings for the prior 12 months. Any revenue adjustments and changes to rates through the FRP rider are reflected in the evaluation report.

There are several categories of costs that the current FRP allows Entergy Louisiana to recover outside the mechanism described above. Some exceptions include recovery of certain investments in capacity and transmission, extraordinary costs; and certain Midcontinent Independent System Operator (MISO) related costs and revenues.

5.5 MYRP Summary

Utility MYRPs consist of several categories: indexed caps, forecast-based rates, and formula rates, though hybrid approaches combining elements of these categories are also common. A hybrid MYRP might blend indexed caps with forecast adjustments or incorporate other forms of

[81] Louisiana Public Service Commission. *Order U-36959*. September 13, 2024.

cost-of-service information, like capital trackers. Because the specific details of each plan vary between jurisdictions, and even between utilities within jurisdictions, no two MYRPs are exactly alike. These differences arise from different utility spending plans, industrial organization (e.g., vertically integrated vs. distribution-only), regulatory objectives, risk tolerance, and precedent.

The design of a MYRP has implications for utility incentives. Whereas indexed caps generally provide enhanced cost efficiency incentives, formula rates have relatively low-cost efficiency incentives. Improved incentives may correspond to higher risks, or, for utilities with particularly lumpy capital investment, a pure indexed approach may simply not be workable given the utility's spending plan. A well-designed MYRP must balance considerations of cost efficiency with feasibility. If a proposed MYRP framework is out of line with the spending forecast of the utility, it will not provide benefits to customers in the long run, no matter how strong the plan's theoretical incentives might be.

Throughout this section, we have reviewed the benefits and challenges of different forms of MYRPs. Each approach presents a different balance of priorities. Table 5.18 provides a summary of these benefits and challenges.

Table 5.18: Benefits and Challenges of Approaches to MYRPs

Approach	Benefits	Challenges
Price Caps	• Provides an annual rate adjustment equal to the rate of inflation minus industry productivity over the MYRP term • Utility can increase revenue and profits through sales growth • Provides cost efficiency incentives	• May result in intervenor resistance to automatic rate increases • Does not protect the utility against sales declines
Revenue Cap + Decoupling	• Provides an annual rate adjustment equal to the rate of inflation minus industry productivity, plus customer count growth over the MYRP term • Protects utility against sales declines • Provides cost efficiency incentives	• May result in intervenor resistance to automatic revenue increases • Does not allow for revenue increases beyond the I-X+G adjustment, even if sales increases occur
Forecasted MYRP	• Provides utility with opportunity to request revenues according to expected costs • Relatively straightforward to implement • Protects utility against sales declines	• Intervenor resistance to automatic revenue increases • Requires more regulatory scrutiny over spending forecasts • Strength of cost efficiency incentives not well established in economics literature
Formula Rates	• Reduces rate application frequency • Aims to keep revenues and costs closely aligned	• Has the lowest cost efficiency incentives (and is not considered to be PBR) • May face criticism related to the evaluation of projects between rate cases.

The regulated electric utilities in Maine already have the opportunity to file MYRPs in the form of an Alternative Rate Plan. Other jurisdictions, like those in Canada, Australia, and Great Britain, have developed standardized MYRP models that all utilities within the jurisdiction must follow. However, these jurisdictions generally contain many more distribution utilities than Maine.

The MPUC could consider creating a set of standard practices that CMP and Versant Power must follow if they file a MYRP. This could be a highly structured, detailed set of rules, or a high-level set of principles.

As explained in **Error! Not a valid bookmark self-reference.**, we recommend that the utilities in Maine follow an indexed cap framework—either a price cap or a revenue cap, though forecasted MRYPs would also be a reasonable approach. The IOUs would file these rate applications as part of the Alternative Rate Plan option that is already in effect.

Table 5.19: Recommendations for MYRPs

Recommendations for MYRPs in Maine	*Maine IOUs are already permitted to file MYRPs as an alternative rate plan. To provide cost efficiency incentives to the utilities, we encourage the adoption of either forecasted or indexed cap MYRPs.* *Furthermore, we note that, as "lines-only" utilities, IOUs in Maine may be well-suited for indexed cap (price cap, revenue cap, or hybrid) PBR frameworks, as these plans provide cost efficiency incentives that may improve customer affordability. We therefore encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans.*

6 OTHER TOOLS IN ALTERNATIVE REGULATION

6.1 Capital Trackers or Project Pre-Approval

Cost of service regulation with regulatory lag can create issues for timely cost recovery, particularly for large capital projects. Under traditional regulation, rate cases set rates according to a utility's embedded costs, but costs associated with new projects are not recovered in base rates until the conclusion of the next rate case. This lack of timely cost recovery can cause hesitation by utilities in making large capital investments. To provide more stable and timely cost recovery, capital trackers that recover revenue on an annual basis have been implemented in many jurisdictions.

Capital trackers can be applied to utilities operating under MYRPs, or by utilities regulated by traditional rate case regulation. As stated in Section 5.2.5, capital trackers can reduce the regulatory lag for utilities, and increase the willingness of utilities to invest in critical infrastructure. However, capital trackers could also lead to capital over-investment and reduce utilities' incentive to control costs.

6.2 Totex

Under the "totex" ratemaking approach, distributors obtain a return on total expenditures (totex), which contains elements of both capital spending (capex) and operating spending (opex). The totex approach to setting returns differs from the traditional approach to setting utility returns, in which only capitalized expenditures earn a return. The totex approach attempts to counter-balance a perceived incentive for utilities to exhibit a capital bias in spending, since capital spending accompanies an allowed return. Under the totex ratemaking approach in Great Britain, utility totex is divided into "Slow Money" and "Fast Money" at a predetermined capitalization rate. "Slow Money" is capitalized and over time, incorporated into the annual depreciation expense, like capex in the traditional approach. The remainder of totex spending, called "Fast Money", is incorporated into the allowed revenue as an expense, like opex in the traditional approach.[82]

The totex approach can also be coupled with an earning sharing mechanism to encourage cost efficiency. In Great Britain, the regulator, Ofgem, set ex ante totex allowances for the utility during the term of each utility's Multi-Year Rate Plan. A sharing factor called the Totex Incentive Mechanism determines companies' exposure to under or overspends compared to the totex allowances. Totex ratemaking approach has been adopted in Great Britain and Italy as a component of utility regulation. Some jurisdictions (e.g., New York and Hawaii) in the US have considered adopting a totex approach, but it is not currently in use in the United States.

6.3 Revenue Decoupling

Revenue decoupling is a regulatory mechanism used in the electric utility industry to separate a utility's revenue from its sales volume. Traditionally, utility profits were directly tied to the amount of electricity sold, creating an inherent incentive for utilities to promote increased energy

[82] "RIIO-ED2 Final Determinations Core Methodology Document," Ofgem, 30 November 2022.

consumption. Decoupling breaks this link, allowing utilities to recover their fixed costs and earn a fair return on investment regardless of fluctuations in electricity sales.

The primary purpose of decoupling is to align the financial interests of utilities with broader energy efficiency and conservation goals. By removing the disincentive to promote energy efficiency, decoupling allows utilities to support and implement energy-saving measures without fear of revenue loss. This regulatory approach aims to create a more sustainable and environmentally friendly energy sector while ensuring the financial stability of utility companies.

Decoupling typically involves setting a revenue target for the utility based on its fixed costs and authorized rate of return. If actual revenues fall short of this target due to reduced energy consumption, the utility is allowed to adjust rates to make up the difference. Conversely, if revenues exceed the target, rates are adjusted downward to return the excess to customers. This mechanism helps to stabilize utility revenues and reduces the financial risk associated with fluctuations in energy demand, while also protecting consumers from potential over-charging.[83]

Is Revenue Decoupling a Form of PBR?

Revenue decoupling mechanisms could be classified as a form of PBR, but this is not universally accepted. If PBR entails emulating the competitive market outcome correcting for any market failures, then revenue decoupling mechanisms can be used to achieve this objective. (For instance, the regulator might worry customer consumption deviates from the social optimum because customers don't internalize the negative externality of environmental impacts.) In any case, revenue decoupling mechanisms are often included in PBR frameworks, so we include a discussion here for completeness.

6.3.1 Revenue Decoupling in Practice

Revenue decoupling mechanisms can be implemented in various ways, tailored to specific regulatory environments and utility structures. These approaches aim to balance the needs of utilities, consumers, and regulatory objectives. One common method allows utilities to adjust rates each year based on the total revenue requirement established during the rate case, such that sales volumes ultimately do not affect realized revenue. This approach ensures that the utility can recover its fixed costs regardless of sales, which may fluctuate as a result of exogenous factors like weather. An alternative approach is revenue-per-customer decoupling.

Regulators may also choose to apply decoupling selectively to certain cost categories. For instance, decoupling may be applied to distribution costs while excluding fuel costs. This selective application recognizes that some costs are more volatile or directly tied to consumption than others, allowing for a more nuanced regulatory approach. Regulators may also establish a cap on rate increases from revenue adjustments. When caps are applied, some regulators may allow excess unrecovered amounts to be carried forward to future periods, while others may not. These variations allow regulators to fine-tune the balance between utility financial stability, consumer protection, and energy efficiency incentives.

[83] It is common for regulators to set a cap to limit price changes from decoupling within a given year to minimize fluctuations.

Figure 6.1 shows adoption of revenue decoupling for gas and electric utilities across the United States. Yellow regions indicate revenue decoupling for both gas and electric utilities, while grey indicates no revenue decoupling is in effect.

Figure 6.1: Revenue Decoupling in the United States[84]

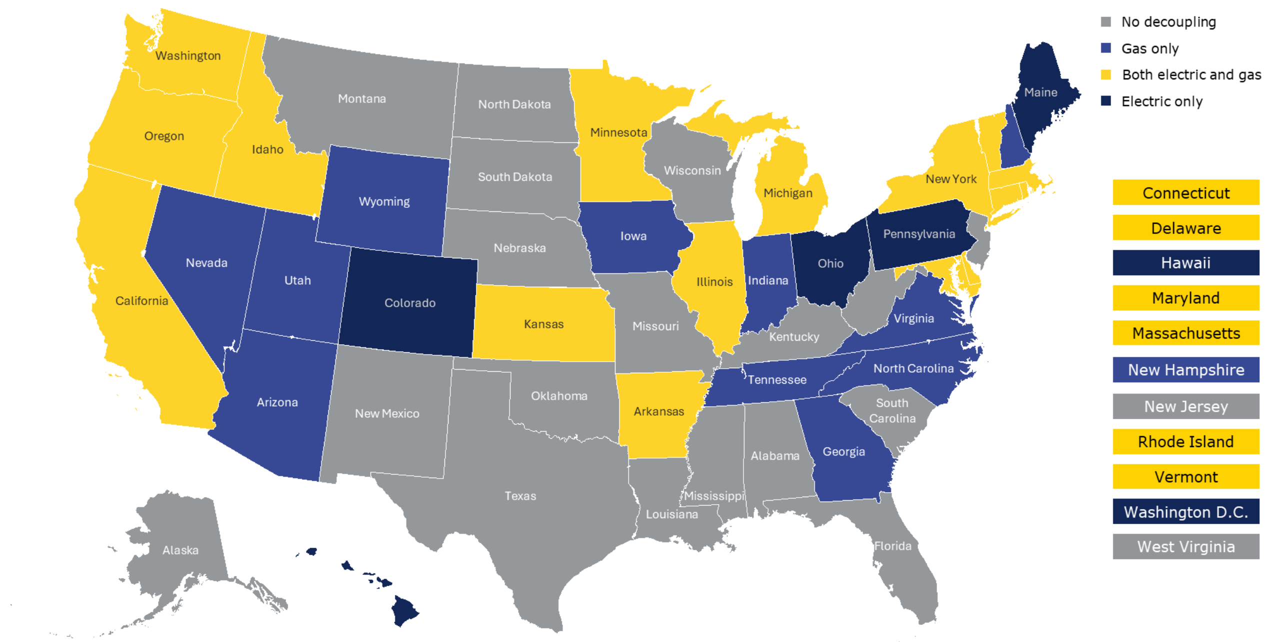


Table 6.1 provides a summary of the advantages and challenges of revenue decoupling. Revenue decoupling was originally designed to remove the disincentive to promote energy conservation by allowing a utility to collect its revenue requirement even if sales volumes decline. Additional benefits include revenue stability and the possibility of less frequent rate cases. Challenges include rate volatility, as customer rates must be adjusted each year as prior year sales volumes fluctuate.

[84] Data for this figure from "Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy," by Daniel Shea, *National Conference of State Legislatures*, April 2023.

Table 6.1: Advantages and Challenges of Revenue Decoupling

ADVANTAGES	CHALLENGES
Energy Efficiency • Removes disincentive to promote energy conservation.	**Rate Volatility** • With annual decoupling adjustments rates are likely to change between rate cases
Reduced Frequency of Rate Cases • In changing sales environments utilities would be able to recover	**Complexity** • Decoupling can make utility rates and regulation more complex, potentially reducing transparency.
Revenue Stability for Utilities • Decoupling reduces utility's reliability on sales volumes.	

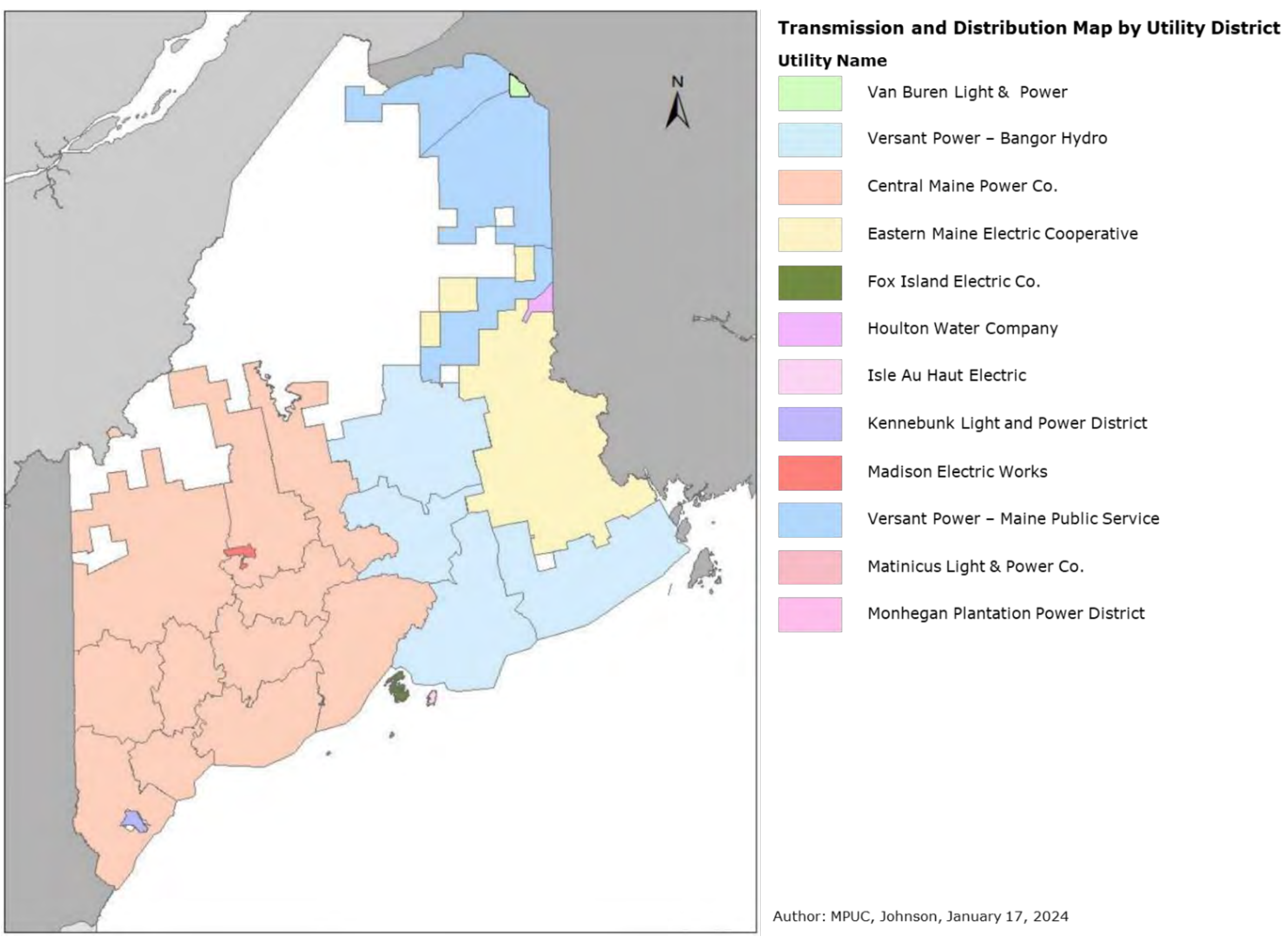
7 MAINE RATEMAKING FRAMEWORK

The state of Maine contains two investor-owned distribution electric utilities: Central Maine Power Company (CMP) and Versant Power —formerly Emera. Versant Power's service territory consists of two distinct districts:

- Bangor Hydro District; and
- Maine Public District.

CMP serves 78% of state's residential load, while Versant Power – Bangor Hydro District serves 13.9% and Versant Power – Maine Public District serves 4.1%.[85] The remaining load is served by cooperatives and municipal-owned utilities, collectively known as Consumer Owned Utilities. Electricity generation is not regulated by the MPUC, and electricity is sold in the New England wholesale market administered by the Independent System Operator of New England (ISO-NE). The wholesale market is different for Northern Maine. There, the electric grid is not connected to the New England grid except by going through New Brunswick, and the Northern Maine Independent System Administrator manages reliability.[86]

Figure 7.1: Transmission and Distribution Map by Utility District[87]



[85] Maine Public Utilities Commission. *Residential Electric Rates.*
[86] Maine Office of Public Advocate. *Wholesale Electricity Market.*
[87] Maine Public Utilities Commission. *2024 Annual Report*. February 1, 2025.

7.1 Industry Overview

In 2000, the Restructuring Act (35-A MRSA, ch. 32) removed Maine's electric utilities from the generation business and required them to sell their various generation assets. The transmission and distribution utilities CMP and Versant Power remain fully regulated by the MPUC. The generation portion of the industry operates in the competitive supply market, and is therefore not regulated by the Commission.[88]

Table 7.1 presents summary information about the state's electricity sector. The state's utilities operate within the ISO New England transmission territory.

Table 7.1: Summary of Maine Electricity Sector

Regulatory Characteristics	
Regulated Utilities	2 IOUs
Ratemaking regulator	Maine Public Utilities Commission
Transmission Operator	ISO-NE
Alternative Regulation Elements	
Cost Trackers	Yes
Revenue Decoupling	Yes
Revenue/Price Cap	No[91]
Formula Rates	No
PIMs	Yes
Earnings Sharing Mechanisms	Yes

Fuel Mix[89]			
Gas	60.5%	Wind	4.8%
Hydro	10.2%	Nuclear	3.5%
Oil	8.9%	Solar	2.1%
Biomass	8.0%	Other	2%

Energy Sector Facts[90]	
Total Installed Capacity	5,252 MW
Total Generation	12.512 GWh
Average Retail Electricity Price	20.84 cent/kWh
Electric Vehicles[92]	7,377
Battery Storage Capacity[93]	63.1 MW[94]

Electricity service in Maine is made up of two parts: supply and delivery (distribution). The price for the supply portion is set within the context of the ISO-NE wholesale market.[95,96] Delivery, on the other hand, is provided by the state's regulated distribution utilities. The regulated rate for delivery consists of four different elements: a transmission charge, a distribution charge, stranded costs (Public Policy Charge), and a conservation charge.[97]

88 Maine Office of the Public Advocate. *Frequently Asked Questions.*

89 Maine Public Utilities Commission, *Residential and Small Non-Residential Standard Offer Service: Consumer Information About Your Electricity* Supply, April 2024.

90 U.S. Energy Information Administration. *Maine State Electricity Profile.* November 6, 2024

91 Central Maine Power operated under an alternative price plan that was discontinued in 2014.

92 Only all-electric vehicles are included. Plug-in hybrid electric vehicles are not included. (Source: U.S. Department of Energy. *Electric Vehicle Registrations by State*).

93 The capacity refers to total deployed capacity at the end of June 2024.

94 State of Maine Governor's Energy Office, *Energy Storage.*

95 Maine Office of the Public Advocate. *Electricity Supply Options.*

96 Maine Office of the Public Advocate. *Electricity Service in Maine.*

97 *Ibid.*

Stranded Costs (Public Policy Charge)

Prior the year 2000, Maine's electric utilities were responsible for generating power. In some cases, prior to deregulation, the utilities signed long term contracts for the purchase of energy from facilities that eventually became too expensive to compete in the competitive generation market. Because the costs associated with uneconomic generation units were approved by the MPUC as recoverable by the utility, such facilities became "stranded" by the transition to a competitive market for generation. Today, the MPUC regularly conducts reviews of these costs to ensure that they are legitimate and that the utilities are making bona fide attempts to reduce them.

In order to promote renewable energy, the MPUC has directed Maine's transmission and distribution utilities to enter into long-term contracts to purchase energy generated from certain Maine renewable energy projects. The utilities are permitted to resell the energy into the New England wholesale market and any difference between the purchase price and the resale price is reflected in stranded cost rates.[98]

Additionally, the stranded costs charge category may also include net energy billing tariff and program costs, a low-income assistance program, and other costs approved by the MPUC.[99,100]

7.2 Ratemaking

In Maine an electric utility rate case begins when a utility files a petition with the MPUC to modify its rates and charges. The time between rate cases for a given utility can vary, as there is no requirement for utilities to file rate cases with particular frequency. However, a utility may not file a schedule for a general increase in rates within one year of a prior filing for a general increase in rates, unless the proceeding initiated by a prior filing was terminated without a final determination of the public utility's revenue requirement or with approval of the commission.[101] When a utility petitions for a rate increase, it has the discretion to propose an alternative rate plan that may include MYRPs, annual adjustments based on indexed formulas and other elements.[102]

Rates for electric utilities in Maine are determined based on utilities' revenue requirement, which is the total revenue the utility needs to cover the costs of serving its customers (shown in Equation 2.1). The revenue requirement, along with the utility's billable outputs, are used to determine rates. As shown in the formula above, the revenue requirement is calculated by adding a utility's operating expenses to its rate base multiplied by an allowed rate of return. Operating expenses are costs incurred by a utility and these costs generally include employee wages and benefits, maintenance, customer services, materials and supplies, energy, and administration costs, as well as taxes and depreciation. A utility's rate base is the historical book

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[98] Maine Office of the Public Advocate. *Frequently Asked Questions.*

[99] Rules of Public Utilities Commission. Chapter 313.

[100] Maine Public Utilities Commission. *Docket 2024-00078*.

[101] Maine Statutes Title 35-A: Public Utilities, Part 1: Public Utilities Commission, Chapter 3: Rates of Public Utilities, §307.

[102] Maine Statutes Title 35-A: Public Utilities, Part 3: Electric Power, Chapter 31: General Provisions, §3195.

cost of plant-in-service less the accumulated depreciation. The allowed rate of return is set to match the utility's cost to obtain capital from lenders and shareholders.

Multi-Year Rate Plans

As noted above, distribution utilities in Maine are allowed to propose alternative rate plans when petitioning for a rate increase. These alternative rate plans generally cover multiple years to reduce the frequency of utility rate cases and can be paired with forecasted or indexed rate increases. In its most recent rate case, CMP proposed to adopt a three-year Multi-Year Rate Plan (MYRP).[103] While the three-year rate plan was not ultimately adopted, the parties to the rate case agreed on a two-year rate plan with a stay-out period that would prevent the utility from initiating another rate case within this timeframe.[104]

CMP has also, in the past, operated under an indexed price cap. CMP's first price cap was implemented in 1995, and the company continued to operate under an I-X price cap for four rate plan periods until it was discontinued in 2014.[105]

A more detailed description of MYRPs and how they have been applied in other jurisdictions was presented in Section 5.

Revenue Decoupling

Utilities in Maine have implemented revenue decoupling mechanisms (RDMs), which separate utilities' revenue from their sales volume. For example, CMP's RDM sets sales levels of kWh and kW based on initial targets adjusted for actual customer growth rates and a factor of 0.75.[106] Differences between the targets and actual sales levels, positive or negative, are then used to determine the revenue adjustment for that year, with annual increases capped at 2% and no cap on a rate decrease.[107] If the company sells more electricity than the target, the excess revenue is returned to customers, and vice versa.

Some of the objectives of revenue decoupling in Maine include a reduction of the financial risk of the utilities and the mitigation of disincentives that utilities might otherwise have to support energy-efficiency measures.[108] CMP first started operating under revenue decoupling in 2014.[109] Since then, CMP's revenue decoupling mechanism has undergone multiple extensions and adjustments, with the most recent approval occurring in their latest rate case.[110] MPUC has also approved a revenue decoupling mechanism for Versant Power in a 2021 decision.[111] Similar to

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[103] Maine Public Utilities Commission. *Docket No. 2022-00152. Central Maine Power Rate Application*. August 11, 2022.

[104] Maine Public Utilities Commission. *Docket No. 2022-00152. Order Approving Stipulation.* June 6, 2023.

[105] Maine Public Utilities Commission. *Dockets No. 92-00345, No. 99-00666, No. 2007-00215 and No. 2013-00168.*

[106] Maine Public Utilities Commission. *Docket No. 2022-00152. Order Approving Stipulation*. June 6, 2023.

[107] Any under-collection amount over the annual cap is deferred for recovery in a subsequent year.

[108] Maine Public Utilities Commission. *Docket 2020-00159.* December 16, 2020.

[109] Maine Public Utilities Commission. *Docket No. 2013-00168. Order Approving Stipulation*. August 25, 2014.

[110] Maine Public Utilities Commission. *Docket No. 2022-00152. Order Approving Stipulation*. June 6, 2023.

[111] Maine Public Utilities Commission. *Docket No. 2020-00316*. *ORDER (Part I).* October 18, 2021.

CMP's RDM, the decision limits any revenue decoupling related annual rate increases to 2%, while adjustments that result in rate decreases are not limited.

Section 6.3 details different revenue decoupling mechanisms, as well as information on which jurisdictions in the United States have adopted revenue decoupling.

Earnings Sharing Mechanism

Earnings sharing in Maine was first introduced with CMP's alternative rate plan effective in 2001, which included asymmetrical earnings sharing mechanism (ESM) that would allow utilities to recover revenue deficiencies should the Return on Equity (ROE) fall below a certain threshold.[112] While the application of a downward-only ESM is uncommon, it was included to balance the increased risk that came with the adoption of a high productivity offset.[113] In CMP's subsequent rate case, the ESM was adjusted to only share utilities overearnings.[114] With the discontinuation of the price cap plan in 2014, the ESM was also discontinued. However, CMP reintroduced an ESM in the Company's most recent rate case in 2023.[115] Versant Power does not currently operate with an ESM.

CMP's recently adopted asymmetrical ESM requires the utility to share 50% of their distribution earnings that exceed an ROE of 10.35% (100 bps above their allowed ROE of 9.35%) with no sharing for revenue deficiencies. The earnings sharing calculation considers any applicable reconciliation mechanisms and is included in CMP's annual compliance filing process. [116]

Cost Trackers

The MPUC is familiar with the application of costs trackers to facilitate timely recovery of certain pre-approved costs that are incurred by utilities. Cost trackers adjust customer rates between rate cases to recover costs that utilities have limited control over, or to recover costs associated with certain capital investments. Adjustments to rates related to cost trackers are made on annual basis with a requirement for utilities to file annual reconciliation or compliance reports.

In its most recent rate case, CMP proposed to implement Capital Adjustment Mechanisms (a form of capital tracker), but this proposal was not agreed upon in the stipulation and was therefore not included in the rate plan.[117] Similarly, Versant Power requested cost tracker treatment of storm costs, but this proposal was not approved.[118]

Due to the "lumpy" nature of capital additions, capital trackers and other capital expense adjustment mechanisms are commonly discussed with the application of PBR. Examples of how capital expenses are handled in different jurisdictions within a PBR context are available Subsections 6.1 and 5.2.5.6.

[112] Maine Public Utilities Commission. *Docket No. 1999-00666. Order Approving Stipulation. November 16, 2000*.

[113] *Ibid.*

[114] Maine Public Utilities Commission. *Docket No. 2007-00215. Order Approving Stipulation*. July 1, 2008.

[115] Maine Public Utilities Commission. *Docket No. 2022-00152. Order Approving Stipulation.* June 6, 2023.

[116] Maine Public Utilities Commission. *Docket No. 2022-00152. Stipulation.* May 31, 2023.

[117] Maine Public Utilities Commission. *Docket No. 2022-00152. Stipulation.* May 31, 2023.

[118] Maine Public Utilities Commission. *Docket No. 2023-00336*. *Order*. March 13, 2025.

Service Quality Indicators (Indices) and Oversight

Maine's regulated utilities face service quality regulation via Service Quality Indicators (SQIs): measurable standards by which the MPUC evaluates the performance of distribution utilities. These indicators encompass a range of metrics including reliability indices such as Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI), customer service response times and billing accuracy. By establishing clear SQI benchmarks and financial penalties for underperformance, the MPUC aims to incentivize utilities to maintain acceptable levels of service. The SQIs currently in place in Maine are very much structured like traditional PIMs. They have a clear performance target that the utilities have to maintain and failure to maintain these performance targets results in penalties. Table 7.2 provides an overview of SQIs currently in place in Maine.

Table 7.2: Summary of Service Quality Indicators[119,120]

Service Quality Indicator (Index)	Central Maine Power	Versant Power	Description[121]
SAIFI	Yes	Yes	Average frequency of sustained interruptions per customer over a predefined area.
CAIDI	Yes	Yes	Average time required to restore service to the average customer per sustained interruption.
Calls Answered in 30 Seconds	Yes	Yes	Share of calls answered by a live person within 30 seconds. It is calculated excluding major event days.
Abandoned Calls	Yes	Yes	Share of calls abandoned. A call is considered "abandoned" if the caller hangs up after the call is received by the utility's automated call answering system and after the customer makes a choice to speak with a live person.
Estimated Bills	No	Yes	Share of bills that are estimated. A bill is considered estimated when an actual meter read is not obtained. The share is calculated by dividing the number of estimated bills with the total number of bills issued.
Bill Accuracy	Yes	Yes	A bill is considered erroneous if: (1) it contains an incorrect rate or charge or charge or is issue to the wrong customer; (2) it lacks a proper charge, fee, or tax; (3) total amount due is not correct; or (4) it is sent to the customer within ten days of the scheduled monthly billing date.
Field Service Requests	No	Yes	Timeliness of responses to field requests.

Both CMP and Versant Power operate under a point system that determines annual rate adjustments. Each SQI is assigned a point value (weight) that determines the maximum penalty (cap) for a given SQI. The penalty amounts are based on the magnitude of underperformance, so that utilities have an incentive to minimize underperformance. For example, underperformance of 3% for a given SQI would lead to a lower penalty than an underperformance of 6%.

[119] Maine Public Utilities Commission. *Docket No. 2023-00336. Examiners' Report*. February 18, 2025.

[120] Maine Public Utilities Commission. *Docket No. 2022-00152. Stipulation*. May 31, 2023.

[121] Maine Public Utilities Commission. *Docket No. 2022-00255*. Stipulation. May 18, 2023.

A key difference between the SQIs applied to CMP and Versant Power is that CMP can offset part of the penalty amount by exceeding performance targets in other SQIs within the same category. SQIs applied to CMP are divided into two categories: (1) reliability metrics, and (2) customer service metrics. Positive performance in each category can only be used to offset penalties within the same category, and improvements in performance are awarded fewer points than a reduction in performance of an equivalent magnitude. For example, the utility receives 2.5 points for 1% improvement in performance and receives -10 points for 1% reduction in performance.

Both utilities are required to file annual compliance reports that include performance metrics and their achievement. The penalties (if applicable) are applied on annual basis.

More detailed information on PIMs and examples of PIMs applied in other jurisdictions is available in Section 4 of this report.

Comparison of Ratemaking Elements

Table 7.3 provides an overview of different ratemaking elements currently applied to each IOU in Maine.

Table 7.3: Comparison of Ratemaking Elements

Mechanism	Central Maine Power	Versant Power
Revenue Decoupling	Yes	Yes
Cost Trackers	Yes	No
PIMs or SQIs	Yes	Yes
Multi-Year Rate Plans	Yes	No
Earnings Sharing Mechanism	Yes	No

7.3 Regulatory Goals in the State of Maine

Articulating the regulatory goals of the state of Maine is a necessary antecedent to assessing potential changes to the existing regulatory framework. A clear set of goals helps to steer policy toward optimizing for the outcomes valued by utilities and their stakeholders. Once a set of goals is established, appropriate regulatory instruments—including, but not limited to, PBR tools—can be identified that could address those goals.

In its assessment of regulatory tools, the MPUC seeks to consider the following objectives:

1. Promote efficient and cost-effective transmission and distribution utility operations;
2. Increase planning and preparation for extreme weather events and climate hazards;
3. Promote cost-effective and comprehensive responses to outages;
4. Increase affordability and customer empowerment and satisfaction;
5. Support achievement of the State's goals for increasing consumption of electricity from renewable resources;
6. Advance the State's greenhouse gas emissions reduction goals established; and
7. Advance beneficial electrification.

These goals are overarching regulatory goals, and are not necessarily specific to the introduction of new PBR elements in Maine. In other words, we do not propose to introduce PBR tools that address each of these goals.

Climate policy currently informs the state's goals for utility regulation (see objectives 5 through 7 in the list above). Legislation in Maine requires the state to use 80 percent renewable energy by 2030, and the government has a goal of transitioning to 100 percent clean energy by 2040.[122] Most of these emissions reductions will need to occur through changes in power generation, which is unregulated and therefore beyond the jurisdiction of the MPUC. PBR tools that aim to address climate initiatives have been applied to distribution utilities in other jurisdictions, indicating that incremental modifications to the existing regulatory framework could address climate goals. However, the effect on emissions of incentives on distribution companies is likely to be small.

The goals set forth by the MPUC, listed above, align with other jurisdictions that are considering updates to electric utility regulation. For example, in its Advancing Performance Based Rate Regulation consultation, the Ontario Energy Board is currently exploring mechanisms that could promote enhanced reliability, affordability, and sustainability through the current energy transition.[123] We think these seven objectives reasonably cover the goals underlying rate regulation.

7.4 Industry Outlook

Maine's electric utilities are navigating a complex landscape with significant near- and long-term uncertainties shaped by infrastructure investments, electrification trends, evolving consumption patterns, and broader economic challenges. Utilities are actively pursuing significant infrastructure upgrades, as evidenced by recent rate cases,[124,125] to replace aging grid infrastructure. Maine's utilities are also navigating a shift toward beneficial electrification, driven by policies aimed at promoting energy efficiency and reducing carbon emissions.[126] These policies combined with financial incentives from third parties,[127] are encouraging the adoption of electric vehicles, heat pumps, and other electric technologies, which can lead to increased electric demand requiring utilities to plan for higher loads.

As electrification accelerates, Maine's historical trend of declining energy consumption since the mid-2000s may slow or even reverse;[128] particularly with the growth of energy-intensive industries such as data centers. This shift in electricity consumption patterns requires strategic planning by utilities to ensure the grid can efficiently manage uncertain loads.

122 Maine Climate Council. *Maine Won't Wait: A Four-Year Plan for Climate Action*. November 2024.

123 Ontario Energy Board. *Advancing Performance-based Rate Regulation*. Ongoing work that began in 2024.

124 Maine Public Utilities Commission. *Docket 2022-00152*. August 11, 2022.

125 Maine Public Utilities Commission. *Docket 2020-00316*. January 19, 2021.

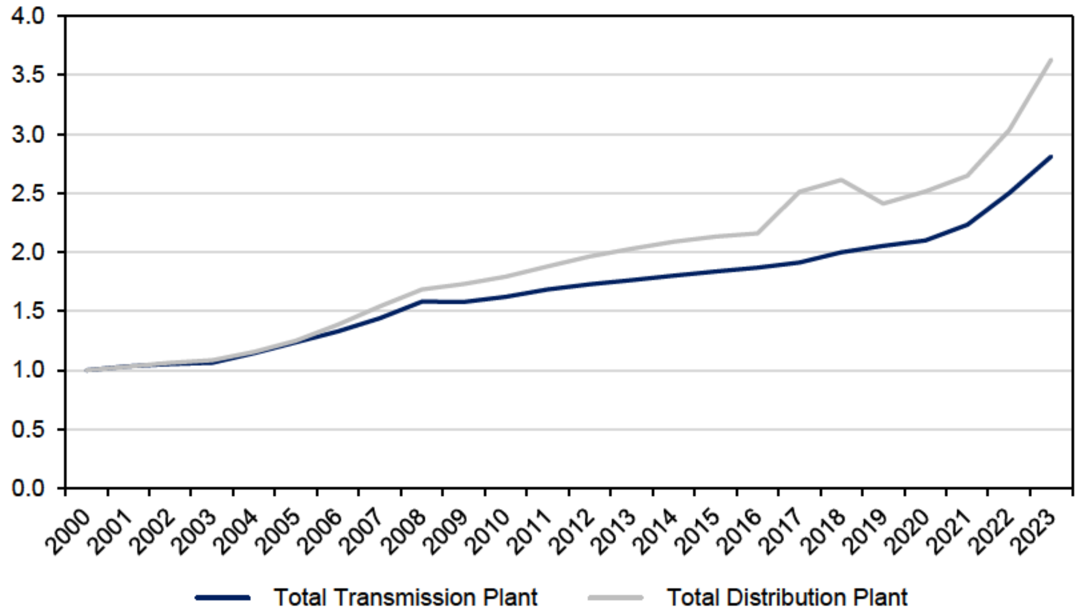
126 Maine State Legislature. Title 35-A, Chapter 38: Beneficial Electrification Policy Act

127 Efficiency Maine. *At Home: Residential Incentives*.

128 U.S. Energy Information Administration. State Energy Data System (SEDS).

In addition, cost pressures have accelerated across the industry. Figure 7.2 below presents a utility industry cost index (known as the Handy-Whitman Index[129]) tracking Total Transmission and Distribution Plant in the North Atlantic region since 2000. The data shows substantial growth in costs over the past quarter century, with a noticeable uptick since the Covid-19 pandemic. Utilities facing these cost pressures and customers paying rates could benefit from indexed cap or forecasted MYRPs, which might encourage cost efficiency while providing a reasonable level of attrition relief.

Figure 7.2: Handy Whitman Index – Total Transmission and Distribution Plant



Ongoing tariffs between the United States and Canada create considerable uncertainty around imports and present an additional challenge for the state of Maine's energy supply. ISO New England imports electricity from Canada,[130] and the tariffs, could lead to broader ripple effects in the economy. The duration of these tariffs and their long-term impacts remain unclear, but given the deep interconnection between the two economies, the effects could extend beyond short-term price fluctuations and potentially influence longer-term consumer behavior and market trends.

[129] The Handy-Whitman Index tracks constructions costs for utility companies across different U.S. regions and is widely recognized by utility companies and regulatory bodies as an authoritative reference for utility cost trends.

[130] Grid Status. *Tariffs Challenge the Interconnected Northeast.* March 5, 2025.

7.5 Could Additional PBR Tools Provide Improvements for Utilities and Customers in Maine?

The MPUC commissioned this study to understand whether PBR tools may be used to address Maine's policy goals for the state's electric utilities, as discussed in Subsection 7.3.

One of the central findings of this report is that the MPUC has already incorporated several PBR elements into its ratemaking structure. These include MYRPs, for example CMP's current MYRP and the company's former price cap, and PIMs in the form of SQIs, which apply to both utilities. Since some PBR elements are already in place in Maine, a question is whether additional PBR tools would assist the state in furthering its regulatory objectives. Newly adopted legislation in the state has granted the Commission with authority to "establish or authorize rate-adjustment mechanisms or quantitative metrics pertaining to public utility's operations and activities in a proceeding for a general increase in rates".[131]

The first step to answering this question is to consider the state's policy goals. As described in Section 7.3, PBR tools have been considered and implemented in other jurisdictions to address policy initiatives similar to the objectives of the MPUC. Some of these regulatory approaches could be introduced to Maine, and others that already exist as options in Maine could be formalized or made mandatory. For example, by formalizing a basic structure for MYRPs and requiring the state's utilities to follow this structure, the MPUC could create a regulatory framework in which utilities might gain more predictable revenues and obtain stronger incentives for cost control and innovation, while consumers might benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared. Formalizing MYRP guidelines could encourage utilities to exercise optional Alternative Rate Plans by reducing the risk that a proposed approach might be rejected.

New PIMs could be used to target specific policy related to the energy transition. These PIMs could include reward -only financial incentives to encourage action beyond traditional utility expectations.

However, while PBR may provide improvements to the status quo regulatory framework, the introduction of new PBR tools does not guarantee improvements. The realization of benefits from PBR requires a well-structured design that accounts for the particular circumstances of the jurisdiction or utility. For this reason, while case studies offer valuable insights, plans that prove successful elsewhere cannot be assumed to replicate that success if applied identically in Maine.

The following two subsections describe PBR tools that might or might not be suitable in Maine, drawing from other jurisdictions where utilities operate under PBR.

7.5.1 PBR Tools for Maine's Consideration

Maine's IOUs are "lines-only" utilities, which means they do not own generation plant. As a state where the IOUs own only transmission and distribution plant, Maine is similar to other jurisdictions where the utilities operate under indexed caps (i.e. price caps or revenue caps). In

[131] "An Act to Allow the Public Utilities Commission to Establish Performance-based Metrics and Rate-adjustment Mechanisms for a Public Utility in Any Proceeding," LD 301, Passed June 2, 2025.

fact, most utilities that operate with an indexed cap are lines-only utilities.[132] This, along with past experience with price caps in the state,[133] suggests that indexed cap PBR could be a viable option for Maine. Section 5.2 provides more detail on how to construct an indexed cap MYRP.

As is the case in Maine, lines-only utilities can also operate under PIMs. While PIMs in Maine only assess a penalty on utilities, with no potential reward, many jurisdictions that have implemented PIMs have adopted reward-only or symmetrical PIMs. Often, PIMs with financial rewards aim to encourage investment or action related to non-traditional utility service, such as meeting policy objectives associated with the energy transition or addressing climate goals. For example, lines-only utilities in Australia, Great Britain, Illinois, and New York operate under targeted mechanisms that provide financial rewards for utility performance in achieving new policy objectives. Section 4.6 provides more detail on these examples. Such jurisdictions could offer a helpful guide to Maine if the state is interested in building on its existing service quality indicators.

While the organization of the state's electricity industry shares some similarities with other jurisdictions that have adopted PBR, this does not mean that identical regulatory tools make sense for Maine. We recommend that the MPUC, utilities, and stakeholders collaborate to determine what new PBR tools make sense to adopt, using this report as a guide.

7.5.2 Limitations to New PBR Tools in Maine

Not all PBR tools make sense to introduce in Maine, and if some tools are adopted, they should be tailored to the state's industrial organization.

Maine's regulated electric utilities own transmission plant within the Independent System Operator of New England (ISO-NE). As discussed throughout this report, utilities that own transmission plant may have larger, lumpier capital investments that could be challenging to regulate under an indexed approach to rate regulation.[134]

In addition, transmission projects for Maine's IOUs are, to a large degree, directed by ISO-NE. As such, substantial portions of the transmission investments made by Maine's IOUs are beyond the control of utility management. In Ontario, electricity distributors operate within the province's Independent Electric System Operator and face indexed cap regulation, but a key difference between Maine and Ontario is that the distributors in Ontario do not own transmission plant.[135] A lack of control over capital projects can make indexed cap regulation more challenging, as the utility may have less ability to manage when and where to make investments. As such, indexed cap PBR, if adopted in Maine, should be accompanied by factors that allow for the recovery of

[132] See for example, Alberta, Ontario, British Columbia (gas distribution only), and Massachusetts. The only vertically integrated electric utility in North America currently operating under an indexed cap is the Hawaiian Electric Companies.

[133] Central Maine Power operated under a price cap until 2014.

[134] Hydro-Québec TransÉnergie, the transmission company in Québec, operated for one four-year period under a revenue cap, but subsequently returned to cost-of-service regulation in 2022 amid issues meeting necessary costs under the cap.

[135] To the extent that the ownership of transmission creates an impediment to adopting price or revenue cap regulation in Maine, an alternative approach could be developed that caps only revenues associated with distribution plant—leaving the transmission portion of the business to remain under traditional COSR. Of course, this may create more administrative complications than its worth.

costs beyond utility management's control (e.g., Y factors, Z factors, and, possibly, capital supplements).

Some jurisdictions, like Hawaii, North Carolina, and Washington state, have implemented PBR tools that make sense for vertically integrated electric utilities,[136] but would make less sense for a lines-only company. Fundamental differences in the industry structure in these jurisdictions mean that the applicable tools in these states likely differ from what can be expected to work in Maine. For example, utilities that own generation plant have more control over the generation mix, and therefore greenhouse gas (GHG) emissions, than utilities that only own distribution plant (like the IOUs in Maine). A PIM aimed at addressing GHG emissions may not work as well in Maine because the utilities do not have ownership of generation assets, and therefore, even strong financial incentives to the utility are unlikely to result in substantive changes to emissions related to power generation. Lines-only utilities can still influence the demand side through the implementation of demand response programs and interconnection of Distributed Energy Resources (DERs), but the effect is likely smaller.

The criteria presented in Section 4.2 can be used to screen potential PIMs. For example, in proposing new PIMs, the IOUs should consider on-going initiatives in Maine, and these PIMs should track outcomes that the utility can reasonably control. In addition, the Efficiency Maine Trust has statutory authority to develop, plan, coordinate, and implement energy efficiency, beneficial electrification and demand management programs in the state, while utilities in Maine play a supporting role in these efforts. This means that some PIMs that may be workably applied to utilities in other states (for example, certain PIMs discussed in Section 4.6) may not be applicable in Maine because the initiatives fall under the purview of the Efficiency Maine Trust.

The design of MYRPs and PIMs in Maine should acknowledge these limitations. MYRPs should allow for exogenous cost factors and possibly allow for transmission to be handled separately from distribution-related costs. In accordance with PIM design considerations described in Section 4.2, new PIMs should address performance that can be controlled by a lines-only utility.

7.6 Stakeholder Input

A draft of this report was published on April 30, 2025.[137] Subsequently, the Maine PUC held a stakeholder engagement workshop on May 14, 2025. Through this workshop, and through written comments, we received helpful feedback from stakeholders that have informed the final version of this report. Some stakeholders commented that PIMs should consider how the utilities' role in demand management programs, energy efficiency, and beneficial electrification differ from utilities in other jurisdictions. Since ratepayers already bear the costs for Efficiency Maine Trust programs, they should not be paying twice for the same initiative.

In addition, stakeholders noted that the challenges of developing reliable baseline data for metrics associated with PIMs must be considered. The introduction of new metrics is not a costless endeavor: the IOUs must expend resources (paid for by ratepayers) in order to create

[136] National Association of Regulatory Utility Commissions (NARUC). *Tracking State Developments of Performance-Based Regulation. PBR State Working Group.* January 2024.
[137] Filed under Docket 2025-00107.

the systems for recording, processing, and reporting data. The calibration of financial incentives also involves development costs.

Stakeholders commented that PBR frameworks need to be carefully designed, as poorly designed framework can create perverse incentives for the utilities. While PBR tools are helpful to address some regulatory goals listed in Section 7.3, given Maine utilities are "lines-only" utilities, other policy tools may be more appropriate to address goals related to greenhouse gas emissions, renewable energy, and beneficial electrification.

Regarding the policy goals, one stakeholder suggested separating "affordability" from goal #4, so that affordability and customer empowerment might be considered separately. Other suggestions were also made regarding the state's regulatory goals.

8 SUMMARY OF RECOMMENDATIONS AND CONCLUSIONS

Electric utilities in the state of Maine already operate under some form of PBR. The existing SQIs provide financial incentives to maintain reliability and customer service quality. We conclude that these tools meet the definition of PIMs, which are PBR tools that provide incentives for the efficient deployment of specific utility outputs. Utilities in Maine also have flexibility to propose MYRPs under an "Alternative Rate Plan." This means that, under the current framework, both CMP and Versant Power could choose to file an indexed cap PBR plan or a forecasted MYRP. The state's approach to the regulation of these companies is similar to other states in the Northeast, like Massachusetts, where utility rate plans with or without PBR elements are assessed on a case-by-case basis.

Additional PBR tools could be introduced in Maine. The MPUC could introduce new PIMs aimed to address certain policy objectives. In addition, the state could standardize requirements for MYRPs. PIMs and MYRPs are generally compatible, but these elements need to be evaluated as a whole. Some consideration should be made on how new regulatory tools affect the utility's cost of capital, as well as the potential cost and benefit to customers.

While the introduction of new tools may provide benefits to customers and to the utilities, these tools also have limitations and drawbacks. This report provides a detailed analysis of the benefits and challenges of the additional PBR tools the MPUC could consider introducing.

8.1 Summary of MYRP Recommendations

Maine IOUs are already permitted to file MYRPs as an alternative rate plan.

Evidence from other jurisdictions indicates that MYRPs can improve utility cost control over time. The organization of the electricity distribution industry in Maine resembles other jurisdictions in North America, as well as in Europe, and Australia, where MYRPs have been implemented successfully in the distribution sector. This finding suggests that indexed cap or forecasted MYRPs, if designed well, are likely to address stakeholder affordability and cost control concerns in the state of Maine. As shown in Table 8.3, we encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans. Table 8.4 presents tenets for a well-designed indexed cap plan.

Alternatively, forecasted MYRPs offer an approach that can provide the regulator with more spending oversight while providing cost efficiency incentives. However, this approach requires the utility to provide clear cost forecast information, and it requires resources from stakeholders to evaluate those spending forecasts.

Cost efficiency incentives through MYRPs may help with affordability but will not resolve all factors driving customer rate increases. A substantial portion of customer rates pertains to generation services, which Maine's IOUs do not provide.

8.2 Summary of PIM Recommendations

Maine's IOUs already operate under mechanisms akin to PIMs under than name Service Quality Indicators (SQIs). These include penalty-only financial incentives for seven measures spanning reliability and customer service. Maine could consider adopting reward-only or symmetrical PIMs to address policy goals currently not addressed in the existing regulatory framework.

We recommend that before instituting any additional PIMs, the MPUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. In the meantime, the MPUC should allow the state's IOUs to propose PIMs on a case-by-case basis as part of the current rate application process.

Table 8.7 summarizes our recommendations regarding PIMs in the state of Maine.

8.3 Recommendation Tables

The tables below comprise the recommendations presented in this report.

Table 8.1: Summary of Guiding PBR Principle Recommendations

Guiding Principles of PBR	*The seven regulatory goals set forth in Section 7.3 stem from the draft legislative language that prompted this investigation. These goals provide an adequate basis for evaluating the regulatory frameworks applied to Maine IOUs, PBR or otherwise.*

Table 8.2: Summary of Revenue Decoupling Recommendations

Revenue Decoupling	*The objective of this report was not to evaluate the existing revenue decoupling mechanisms of the Maine IOUs. However, we note that if an IOU develops a MYRP, the design of the framework must consider the interaction between the RDM and the MYRP.*

Table 8.3: Summary of MYRP Recommendations

Recommendations for MYRPs in Maine	*Maine IOUs are already permitted to file MYRPs as an alternative rate plan. To provide cost efficiency incentives to the utilities, we encourage the adoption of either forecasted or indexed cap MYRPs.* *Furthermore, we note that, as "lines-only" utilities, IOUs in Maine may be well-suited for indexed cap (price cap, revenue cap, or hybrid) PBR frameworks, as these plans provide cost efficiency incentives that may improve customer affordability. We therefore encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans (with further recommendations in Table 8.4).*

Table 8.4: Summary of Indexed Cap Recommendations

Indexed Caps	*We encourage the Maine IOUs to propose, and the Maine PUC to accept, indexed cap plans rooted in the I-X formula.*
Indexed Cap Inflation Factors	*If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an inflation factor be included in the PBR formula (I-X). The inflation factor should be established to reflect the electric utility sector's annual input price growth. If an output price measure of inflation is used, the X factor must be adjusted accordingly.*
Indexed Cap X Factors	*If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an X factor be included in the PBR formula (I-X). This X factor should be calculated on the basis of an industry TFP growth or Kahn Methodology.*
Indexed Cap Stretch Factors	*If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a stretch factor be included in the formula (I-X-S). This stretch factor should be company-specific informed by an industry cost benchmarking analysis.*
Z Factors	*If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Z factor be included in the PBR framework. The Z factor should be*

	company-specific and have a materiality threshold roughly in line with thresholds seen in other jurisdictions.
Y Factors	*If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Y factor be included in the PBR framework. The Y factor should be company-specific and the costs eligible for Y factor treatment should be clearly defined at the outset of the PBR term.*
Capital Factors	*If the Maine IOUs operate under an indexed cap regulatory framework, we recommend that some form of capital supplement be included on an as-needed basis. The capital factor should be company-specific and the costs eligible for capital factor treatment should be clearly defined at the outset of the PBR term. We recommend adopting capital factors that provide cost efficiency incentives, such as a forecasted capital or K-bar approach, when possible.*
Reopeners	*If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, we recommend that some form of reopener be included. The reopener provision should have a clearly defined trigger and a clear description of how the mechanism would be applied in the event of being triggered.*
Earnings Sharing Mechanisms (ESM)s	*If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, utilities or utility stakeholders may wish to incorporate ESMs. ESMs are not necessary elements of a regulatory framework. However, if ESMs are adopted, we recommend wide deadbands in order to maintain cost efficiency incentives. For example, sharing only after a 200+ basis point deviation from allowed ROE.*
Efficiency Carryover Mechanisms (ECMs)	*If the Maine IOUs operate under a MYRP regulatory framework, we recommend consideration of Efficiency Carryover Mechanisms as a way to maintain cost efficiency incentives over rebasing periods.*

Table 8.5: Summary of Forecasted MYRP Recommendations

Forecasted MYRPs	*We recommend Maine IOUs continue to be permitted to voluntarily file forecasted MYRPs. We further recommend consideration of MYRP terms longer than the two-year plan currently applied to CMP (for example, three or four years). We note that indexed cap plans may offer more simplicity and better cost efficiency incentives, depending on the plan design.* *If three- or four-year forecasted MYRPs are adopted, these plans may include additional elements discussed in Table 8.4. For example, exogenous cost factors (Z and Y factors) may be included, as well as reopener provisions.*

Table 8.6: Summary of Formula Rate Plan Recommendations

Formula Rate Plans	*We do not currently recommend that Maine IOUs pursue formula rate plans. However, if IOUs face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered.*

Table 8.7: Summary of PIMs Recommendations

Recommendations for PIMs in Maine	*1. We recommend that the Maine PUC allow the state's IOUs to file new PIMs as part of future rate applications, to be assessed on a case-by-case basis. We recommend using the guidelines provided in Section 4.2 in the design of these PIMs.* *2. We recommend that before instituting any mandatory PIMs or any PIMs that apply to all IOUs, the Maine PUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. We recommend following the criteria set out in Section 4.2 prior to implementing mandatory PIMs.*

APPENDIX A: GLOSSARY OF ABBREVIATIONS

Abbreviated Term	Full Term	Abbreviated Term	Full Term
AMI	Advanced Metering Infrastructure	IOU	Investor Owned Utility
ARM	Attrition Relief Mechanism	ISO-NE	Independent System Operator New England
AUC	Alberta Utilities Commission	MISO	Midcontinent Independent System Operator
BCUC	British Columbia Utilities Commission	MPUC	Maine Public Utilities Commission
CA Energy Consulting	Christensen Associates Energy Consulting	MYRP	Multi-Year Rate Plan
CAIDI	Customer Average Interruption Duration Index	NYPSC	New York Public Service Commission
CAPEX	Capital Expenditure	NYSEG	New York State Electric & Gas
CMP	Central Maine Power	ODI	Output Delivery Incentives
COSR	Cost-of-Service Regulation	OEPX	Operating Expenditure
CPI	Consumer Price Index	PBR	Performance-Based Regulation
CSPI	Customer Service Performance Mechanism	PCR	Price Cap Regulation
DEC	Duke Energy Carolinas'	PIM	Performance Incentive Mechanism
DER	Distributed Energy Resources	PUC	Public Utilities Commission
EAM	Earnings Adjustment Mechanisms	PURPA	Public Utility Regulatory Policy Act
ECM	Efficiency Carryover Mechanisms	RDM	Revenue Decoupling Mechanism
EPCOE	Evaluation Period Cost of Equity	REV	Reforming Energy Vision
EPRM	Exceptional Project Recovery Mechanism	RIIO	Revenue using Incentives to deliver Innovation and Outputs
ESM	Earnings Sharing Mechanism	RMI	Rocky Mountain Institute
EV	Electric Vehicle	ROE	Return on Equity
FERC	Federal Energy Regulatory Commission	RPM	Reliability Performance Mechanism
FFR	Fast Frequency Response	RPS-A	Renewable Portfolio Standard-Accelerated
FRP	Formula Rate Plan	SAIDI	System Average Interruption Duration Index
FWI	Fixed Weight Index	SAIFI	System Average Interruption Frequency Index
GDP-PI	Gross Domestic Product Price Index	SQI	Service Quality Indicator (Index)
GHG	Greenhouse Gas	TFP	Total Factor Productivity
HECO	Hawaiian Electric Companies	TOTEX	Total Expenditure

APPENDIX B: INDEXED CAP DERIVATIONS

B.1 Price Cap Derivation

The derivation for a utility's cap in price growth follows from the theory of competitive markets, as PBR attempts to induce growth in price that one would observe if the regulated company were in fact operating in a competitive market. In competitive markets, firms earn zero economic profit[138]. This is generally understood best by example; suppose a firm operates in a competitive market and is able to rent capital at a low price and use this rented capital along with labor and materials to produce goods at an output price that allows for positive economic profit. In this case, profit-seeking competing firms will enter the market and copy this strategy, bidding up the price of capital until profits are zero. Thus, it must be the case that revenues equal economic cost:

$$Revenue = Economic\ Cost$$

$$\sum p_i q_i = \sum w_j z_j$$

Where p_i is the price of output i, q_i is the number of units of output i, w_j is the price of input j, z_j is the number of units of input j, and the notation $\sum x_i$ is shorthand for x_1+x_2+...x_n if i takes on values from 1 to n. For example, the utility's three billable outputs might be energy (KWh), demand (KW) and total customers. In the first case, the utility has a price per KWh (p_{KWh}) and a total KWh delivered to customers (q_{KWh}) that when multiplied together yields total revenue from energy sold. On the input side, as an example, the utility might have three input: labor, capital, and materials. If the utility hires z_{Labor} employees and pays a wage of w_{Labor}, the cost of labor can be calculated by multiplying these terms together. Therefore, its revenue is $p_{KWh}q_{KWh}$ + $p_{demand}q_{demand}$ + $p_{customers}q_{customers}$ and its costs are $w_{labor}z_{labor}$ + $w_{capital}z_{capital}$ + $w_{materials}z_{materials}$, which can be written a compact way as shown above, for i in $[KWh, demand, customers]$ and j in $[labor, capital, materials]$.

The task of calibrating a price cap is to figure out how prices should move in response to exogenous changes in input price and outputs (say, demand and customer growth) to allow the utility enough revenue to cover its costs. This can be achieved by studying how the revenue equals cost relationship changes over time when prices, outputs, and inputs change:[139]

$$\sum \dot{p}_i q_i + \sum p_i \dot{q}_i = \sum \dot{w}_j z_j + \sum w_j \dot{z}_j$$

Roughly speaking, the notation $\dot{x}$ can be interpreted as the change in x over time.[140] To convert this expression to growth rates rather than level changes, we can begin by multiplying and

[138] Economic profit includes opportunity cost. For instance, if a firm owns its capital, the amount it can earn in rent payments from leasing it to businesses should be included as a cost.
[139] This is derived by totally differentiating the revenue equals cost expression with respect to time.
[140] Technically, it is the derivative of x with respect to time, or dx/dt.

dividing each term by level of the variable that has been differentiated, since this ratio is 1 and thus the equality still holds:

$$\sum \dot{p}_i q_i \frac{p_i}{p_i} + \sum p_i \dot{q}_i \frac{q_i}{q_i} = \sum \dot{w}_j z_j \frac{w_j}{w_j} + \sum w_j \dot{z}_j \frac{z_j}{z_j}$$

We can then divide the left-hand side by total revenue and the right-hand side by total cost, since these quantities are equal and so the equality still holds. We can then rewrite the expression in terms of revenue and cost shares, noting that

$r_i = \frac{q_i p_i}{Revenue}$, or output $i's$ revenue share, and

$c_i = \frac{w_j z_j}{Cost}$, or input $j's$ cost share

Doing so changes the expression to

$$\%\Delta Revenue = \%\Delta Cost$$

or,

$$\sum r_i \frac{\dot{p}_i}{p_i} + \sum r_i \frac{\dot{q}_i}{q_i} = \sum c_j \frac{\dot{w}_j}{w_i} + \sum c_j \frac{\dot{z}_j}{z_i}$$

The first term is the sum of the percentage changes in output prices, where each price is weighted by its share in revenue. It can be interpreted as the percentage change in the price index.[141] The other terms take the same form, and represent percentage changes in the output index, the input price index, and the input index, respectively. Rewriting to make this clear,

$$\%\Delta P + \%\Delta Q = \%\Delta W + \%\Delta Z$$

Solving for $\%\Delta P$,

$$\%\Delta P = \%\Delta W - (\%\Delta Q - \%\Delta Z)$$

$$\%\Delta P = I - X$$

where $I = \%\Delta W$ and $X = \%\Delta Q - \%\Delta Z$

There are several possible choices for X. The first choice is the company's own projected productivity growth. In this case, the company will earn zero profit essentially by design. Another choice, which is the standard approach, is to let X be the average productivity growth in the industry. This latter choice forces the company to match the industry's productivity rate in order to at least break even. However, note that neither choice ideally emulates competitive markets, since the industry productivity rate is not reflective of a competitive market. This is an important part of the motivation behind the stretch factor, discussed above.

[141] This percentage change is referred to as a Tornqvist index.

In some jurisdictions it is common to use a measure of output inflation rather than input inflation. In this case, the price cap can be derived by noting that, if one assumes the economy as whole is competitive, the same relationship holds for the economy:

$$\%\Delta P_{econ} = I_{econ} - X_{econ}$$

$\%\Delta P_{econ}$ is output price inflation, which is the inflation measure used for the utility's price cap in this case. An example of $\%\Delta P_{econ}$ is the growth rate of the GDP-PI. A measure of economy-wide total factor productivity growth is estimated annually, and so together with the GDP-PI, I_{econ} can be recovered as the sum of these two growth rates based on the above equation. Combining this equation with same equation derived for the average company in the industry (with the X that incentivizes the firm to at least match the productivity of the average company), the two equations can be subtracted to yield

$$\%\Delta P_{ind} - \%\Delta P_{econ} = (I_{ind} - I_{econ}) - (X_{ind} - X_{econ})$$

$$\%\Delta P_{ind} = \%\Delta P_{econ} - [(I_{econ} - I_{ind}) + (X_{ind} - X_{econ})]$$

which is the appropriate price cap when a measure of output price inflation is used.

In summary, there are two common price caps, depending on whether an input or output price inflation measure is used. When the appropriate measure of input price inflation is used, the cap is

$$\%\Delta P = I_{ind} - X_{ind}$$

When a measure of output price inflation like the growth rate in the GDP-PI is used, the cap is

$$\%\Delta P = \%\Delta P_{econ} - [(I_{econ} - I_{ind}) + (X_{ind} - X_{econ})]$$

B.2 Revenue Cap Derivation

In B.1, we derived the formula for the price cap:

$$\%\Delta P = I - X$$

This was derived by noting that, in competitive markets,

$$\%\Delta Revenue = \%\Delta Cost$$

$$\%\Delta P + \%\Delta Q = \%\Delta W + \%\Delta Z$$

Thus, $\%\Delta Revenue = \%\Delta P + \%\Delta Q$.

For a given price cap $\%\Delta P$, adding on $\%\Delta Q$ yields the corresponding revenue cap $\%\Delta Revenue$. This factor $\%\Delta Q$ is often called the "growth factor", and is represented by the term *G*.

APPENDIX C: PBR PRINCIPLES IN OTHER JURISDICTIONS

C.1 Alberta

Gas and electric distribution utilities in the province of Alberta have operated under PBR for over a decade. In the original decision that organized PBR in the province, the Alberta Utilities Commission published the following guiding principles:[142]

Principle 1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

Principle 2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

Principle 3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

Principle 4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.

Principle 5. Customers and the regulated companies should share the benefits of a PBR plan.

C.2 British Columbia

The BCUC determined that the principles listed below should guide its assessment of the efficacy of the multiyear rate plans proposed by FortisBC Energy Inc. (FEI) and FortisBC, Inc. (FBC) (together, FortisBC).[143] These principles align closely with the principles adopted by the Alberta Utilities Commission (AUC) for the PBR plans in effect in Alberta. As noted by the AUC, there is a high degree of consensus on the principles that should guide the development of PBR.

1. The PBR plan should, to the greatest extent possible, align the interests of customers and the utility; customers and the utility should share in the benefits of the PBR plan.

2. The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

3. The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.

4. The PBR plan should maintain the utility's focus on maintaining safe, reliable service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.

[142] Alberta Utilities Commission. *Regulated Rate Initiative – PBR Principles*, *AUC Bulletin 2010-20*. July 15, 2010. p. 2.
[143] British Columbia Utilities Commission. *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, *Decision and Orders G-165-20 and G-166-20*. June 22, 2020. p. 168.

5. The PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

C.3 Ontario

In its Renewed Regulatory Framework, the Ontario Energy Board concluded the following outcomes are appropriate for consideration when evaluating utility rate applications.[144]

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable

C.4 Massachusetts

In addition, the Department established a number of factors it would weigh in evaluating incentive proposals. These factors provide that a well-designed incentive proposal should:[145]

1. Comply with Department regulations, unless accompanied by a request for a specific waiver;
2. Be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services;
3. Not result in reductions of safety, service reliability, or existing standards of customer service;
4. Not focus excessively on cost recovery issues;
5. Focus on comprehensive results;
6. Be designed to achieve specific, measurable results; and
7. Provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. These objectives mesh with the guiding principles of PBR established in other jurisdictions.

[144] Ontario Energy Board. *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*. October 18, 2012. p. 57.
[145] Massachusetts D.P.U. *Docket 94-158*. p. 57.

C.5 Hawaii

PBR Guiding Principles:[146]

1. A customer-centric approach. A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers.
2. Administrative efficiency. PBR offers an opportunity to simplify the regulatory framework and enhance overall administrative
3. Utility financial integrity. The financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers and PBR framework is intended to preserve the utility's opportunity to earn fair return on its business and investments, while maintaining attractive utility features such as low cost capital.

[146] Hawaii Public Utilities Commission. *Decision and Order No. 36326*. May 23, 2019. p. 6.

MAINE PUBLIC UTILITIES COMMISSION
AUGUSTA, MAINE

IN RE:)
) Docket No. 2025-107
MAINE PUBLIC UTILITIES COMMISSION) May 16, 2025
)

Inquiry Into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

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CONFERENCE COMMENCED (May 16, 2025, 9:00 a.m.)

MS. HEALY: Good morning, everyone. This is a Commission-initiated inquiry into performance-based regulation of investor-owned transmission and distribution utilities. This is docket number 2025-00107. I want to first of all thank you all for taking time out of your schedules to participate in today's workshop. Stakeholder input is very important in this process, and we're hoping that people will not be shy about speaking up and sharing their views. This workshop was noticed in an April 30, 2025 Notice of Inquiry. I'm Nora Healy. I'm the presiding officer in the case. I know that Commissioner Gilbert is on Teams and -- oh, and Commissioner Scully is on Teams as well, and Chair Bartlett may join at some point. To my right is Derek Davidson. To my left is Michael Simmons and Ethan Grumstrup who are the staff assigned to this case. And as -- today, we also have with us Christensen -- from Christensen Associates Energy Consulting on Teams, we have Nick Crowley. And, Nick, I think your camera's on. That's great. And, Nick, I think Sherry Wang is also with you today. Is that correct?

MS. WANG: Yes.

MR. CROWLEY: Yeah, we have a couple of team members on, the folks who authored the report.

MS. HEALY: Okay. So because I cannot pronounce Andi's last name, I'll let you identify Andi and your other teammate Corey.

MR. CROWLEY: Sure. So we have Sherry, Corey Goodrich, and Andi Romanovs-Malovrh. Andi, give me a thumbs up if I've got that right. All right. So that's the Christensen team.

MS. HEALY: Okay, great. And I know that Corey Goodrich was also listed as an author, but I think we've got the key -- oh, he's on great. Thanks. Apologize. I had to take a little cold medicine this morning. So as indicated in the Notice of Inquiry, the purpose of today's workshop is allow the -- to allow the Commission to collect stakeholder input regarding Christensen's draft report. In particular, the Commission is seeking input related to the goals of PBR set forth in the draft report as well as what specific PBR structures make sense for Maine. I'm not going to take appearances from everyone right now, but if you speak, I'd ask that you please state your name and the entity that you represent before you speak at least the first time. I don't -- we don't -- it doesn't look like we have a ton of people. We also have a sign-in sheet for people that have -- are in the room so that they can provide their identification as well.

We are recording and transcribing and streaming this. The transcript and the slides from Christensen's presentation will be posted in the docket. The process for today's workshop is, again, people that are here in person, please sign the sign-in sheet, and the workshop's going to begin with a presentation by Christensen related to the draft report. That draft report was attached to the Notice of Inquiry. We ask that you generally hold your questions and comments until after Christensen's gone through their presentation, and then we'll be opening up the workshop to discussion. And, again, we certainly encourage a robust discussion. We'll -- if -- we'll plan to break around 10:30. And we -- depending on where we're at, we would (indiscernible) 10:30. We will stop at noon.

Following the workshop today, we encourage people to submit written comments regarding the draft report. Those written comments are due on May 30th, 2025. Anyone can submit written comments. You don't need to have attended the workshop to submit them. Following the submission of those comments, the Commission and Christensen will review and consider them. Christensen will finalize its report and add recommendations to its report. The Commission anticipates submitting the report to the legislature, including a transcript of this workshop and any written comments as well.

A couple notes about etiquette. We're not using the meeting chat for this meeting. The transcript will capture the discussion. If you're on Teams and you want to speak, please raise your hand in Teams. If you're in the room and you'd like to speak, make sure you speak directly into the microphone. And, again, if you're going to speak, please state your name and the entity that you represent. Are there any questions before we get started? Okay, great. Michael?

MR. SIMMONS: Do you want to -- is it worth kind of going -- not doing appearances but at least mentioning the organizations that are here just for Christensen --

MS. HEALY: That --

MR. SIMMONS: -- that might be helpful.

MS. HEALY: Sure, let's do that. We'll start with David.

MR. LITTELL: Not appearances. Versant Power.

MS. HEALY: Yeah.

MR. QUALEY: And Richard Qualey also here with David Littell of Bernstein Shur on behalf of Versant Power.

MS. TUGGEY: Carly Tuggey, general Counsel, CMP, and Peter Cohen, VP regulatory.

MS. CHAMBERLIN: Susan Chamberlin, Office of the Public Advocate.

MR. MARSHALL: Yeah, and Brian Marshall for the OPA as well.

MR. BURNES: We have Becca Ferguson and Ian Burnes from Efficiency Maine Trust.

MS. HEALY: And why don't we just -- on Teams, I know we have Commissioners Gilbert and Scully. I do see the representatives of the Governor's Energy Office. Kiera, if you want to introduce yourself, you're welcome to.

MS. REARDON: Yes, thank you, Nora. This is Kiera Reardon with the Governor's Energy Office, and we have a few team members with us today learning: Sy Coffey, Lindsay Gilton, and Kelly Strait.

MS. HEALY: Okay. Is there anyone else on Teams that would like to identify themselves? Okay, then I'm going to turn it over to Nick and Christensen for the presentation. Thank you.

MR. CROWLEY: Thank you, Nora. So let me just make this a full screen. Is everyone able to see this?

MS. HEALY: Yes.

MR. CROWLEY: Great. One note, Nora. I have made a few updates to the slides since the version that I sent you. So I would ask that you hold off on posting this to the docket until after the workshop, and then I'll just send along the current version. Does that work?

MS. HEALY: Yes, it does.

MR. CROWLEY: Great. Okay. So thank you, everyone, for taking the time this morning to discuss performance-based regulation in the state of Maine. What I intend to do in this brief presentation -- the presentation itself is supposed to last about 30 minutes, and then the rest of the time can be spent in discussion. The goal is to, at a high level, present the findings of our report which we produced a few weeks ago and then provide the opportunity for stakeholders to give feedback and thoughts on next steps and things like that. So the report was authored by myself and then the other Christensen folks who are on this call, Sherry, Corey, and Andi, who were instrumental in helping put together the research and the writing of the report. Before we get too far, I would like to spend just a minute talking about our firm and the work that we do just to set the stage about what our background is. So Christensen Associates was formed -- it's a consulting firm that was formed in 1976 here in Madison, Wisconsin. The very beginning of our firm was doing work that has to do with performance-based regulation. That work was productivity analysis, total factor productivity, and we were doing that work in the 1970s and 80s for the U.S. Postal Service and then the telecommunications industry which went under a form of price cap PBR for a while in the 80s and 90s. And then our work evolved into the world of electric and gas utilities, railroads, and oil pipelines. And so the tools of PBR that we'll talk about today are tools that span not just the utility industry but many industries, and our firm has been working in those industries with those tools for many decades. Our work covers, as you can see, total factor productivity, cost benchmarking, performance incentive mechanisms, regulatory framework design. That's the kind of work that we do in the PBR sphere. There are any number of other things that we do with electric and gas utilities outside of PBR, more conventional rate design, cost of service, or cost allocation, cost of capital, things like that. So our firm is -- it's a firm that has an energy practice, and within that energy practice we do a number of different things.

My own background, I'll say briefly, is I've been with the firm for about nine years. Most of my time during that nine years has been spent doing performance-based regulation work in Massachusetts, Alberta, British Columbia, Ontario, Indiana, New Hampshire, and now Maine, as well as some kind of national work in -- before the FERC. So that's my background. Our team is a bunch of really great and smart people who are able to synthesize information from all different jurisdictions and think creatively about, you know, regulatory solutions. So that's the background.

Let's talk about the workshop outline. The first thing to do is to set the stage about why we're here, what is the project background and the purpose of the meeting. Then I'll spend a minute defining performance-based regulation and the two tools, the kind of over-arching categories of tools as we see them, of PBR. Then we'll look at Maine's existing tools and policy goals, we'll talk about PPR tools for consideration in Maine, and then finish with observations and next steps.

So let's briefly talk about the project background. I think most people who are here understand why we're here. We're here to evaluate PBR tools that may be used to regulate investor-owned utilities in the state of Maine. And there's a scope to this work which is to review what has been done elsewhere. That includes other states, but also we've spent quite a bit of time evaluating and looking at regulatory frameworks in other countries, like, for example, Canada and Great Britain and Australia. So we can bring that information to bear on what might be helpful for the state of Maine and then assist the Commission with developing goals and translate those goals into performance-based standards and metrics and then identify emerging regulatory mechanisms that would help align utility performance with these state policies.

So that's the scope of work and what we hope to convey in our report as well as in our discussion today. What we want to do is just present what we've got in that report, and then a critical part of the meeting today is to hear feedback from stakeholders. I know sometimes it can be -- you know, I've given quite a few stakeholder engagement meeting presentations, and there's -- there always seems to be hesitation with voicing opinions or giving thoughts. And I would encourage you to do away with that hesitation because this report, if you've read the report, you can see that there are placeholders which says to be finalized after stakeholder input. And if -- you know, it's incredibly helpful for us to provide recommendations that are helpful for Maine if we hear what people in Maine and the different stakeholder groups in

Maine think about what works or what is needed in the state. So please, either today in this meeting or in subsequent written feedback, it's very helpful to hear your thoughts.

So let's move into kind of the real meat of the presentation which is define -- you know, getting into performance-based regulation, defining what it is that we're really looking at. So I think, from hearing the introductions of folks around the table and also who are in various places on Teams, it sounds like there -- most of the folks here have pretty good experience with the way that regulation works in the utility industry and especially in Maine. But if there are any people on the call who are maybe less familiar, I'll take a minute just to set the table. I think the best way to talk about alternative regulation is first to define what traditional regulation is and just say at a high level what that looks like. So I'll do that briefly. Traditional regulation -- under traditional regulation, what happens is electric and gas utilities, they have occasional rate applications or rate cases where they put together an accounting of all of their costs to determine what's called a revenue requirement. That revenue requirement is then allocated across customer classes and used -- and a certain kind of mechanism called the cost of service study is used to inform rate design for all the customers on its system. Rates are set through a proceeding that is mediated by the regulator, and different stakeholder groups have the ability to provide intervening input or testimony. And then usually there's direct testimony and then rebuttal testimony, and then rates are established by the Commission at the end of that rate application. And then the utility is able to operate with those rates until it decides to file its next rate application.

So that's traditional regulation, and alternative regulation is really anything that deviates from that. And so it's a really broad umbrella. And that's what the figure on this slide is trying to depict is that there's all these different what I would call tools that deviate from alternative -- that deviate from traditional regulation. Some of these alternative regulation tools we would consider to be performance-based regulation tools and some of them wouldn't be. So if you look at this figure, the items that are in the yellow portion of the diagram are alternative regulation but not necessarily performance-based regulations. So, for example, earnings sharing mechanisms, that's something that isn't defined under traditional regulation as I just described it, but it also doesn't improve the incentives of the utility to become more, for example, efficient because it actually reduces efficiency incentives for the utility. So alternative regulation and performance regulation, they're not synonyms. What is performance-based regulation? Really it's a subset of alternative regulation that focuses on incentives, and I'll talk a little bit more about what that means in the next slide. But as a result of that, performance-based regulation is also called incentive regulation. So you can see there's a couple of tools that are almost always considered PBR. Those would be price caps, revenue caps, and performance incentive mechanisms which are also known as PIMs. Then there's some tools that you might define as PBR. It kind of depends on how you set up the plan. So multi-year rate plans, in some cases depending on how you set it up, could be a form of PBR or maybe like a light form of PBR. And that actually brings me to maybe the final point before I move on from this slide which is that PBR is not -- despite what this figure shows -- the figure makes it seem like everything is all nice and neat, well defined. There's something you can put in one category that's not in another category, but that's really not the case. PBR is a -- is really a spectrum. The incentives of any regulatory framework lies on some spectrum. And we have a figure in our report that shows that which says there are some forms of traditional regulation, depending on how you kind of set it up, that have fairly good cost efficiency incentives for a utility, for example. Or at least, you know, it could be worse. So I think that's just something to keep in mind. When we talk about PBR, we're not talking about a binary choice between is it PBR or is it not PBR because the line gets blurry.

Let's talk about the fundamental tools of PBR. We view there as -- we view there being two tools of PBR: multi-year rate plans and performance incentive mechanisms. And multi-year rate plans have two categories, kind of two over-arching categories which are forecasted multi-year rate plans where the utility forecasts its required revenues over a period of time, and the other one is index caps where the rates or the revenues are adjusted each year based on something that's not in the control or -- it's not in the control of the utility. But the fundamental principle of multi-year rate plans is that the utility is not able to come back in for a rate application at will. It has made some kind of agreement that it will stay out of a rate case for a period of time, and that could be as short as two years, it could be as long as ten years or, you know, as long as you could imagine. But the typical amount -- the typical length of a multi-year rate plan is something like three to five years depending on how it's set up.

So let's just talk a little bit more about multi-year plans before I move on to PIMs. Multi-year rate plans, the purpose of multi-year rate plans, generally speaking, is to try to incent the utility to produce outputs using the least costly combination of inputs. So if we turn our attention to the figure on this slide, you can see there's a number of inputs that any utility needs in order to produce its outputs. So those inputs include capital O&M, fuel, you can imagine other things in -- within those categories. And then the utility takes those inputs and produces outputs. Those outputs are, you know, energy, customer connections, capacity, and then a lot of other things that are often forgotten which is reliability, different rate programs. There's a huge amount of outputs that are not necessarily billed to customers that the utility provides. So the goal of a multi-year rate plan is to say if we want to get these outputs, let's incent the utility to provide those outputs at the least costly combination of inputs. So that's the goal of multi-year rate plans.

Turning to PIMs or performance incentive mechanisms, now we focus on outputs. The question is, okay, what are the outputs that we want the utility to focus on and how do we get the utility to focus on those outputs. Usually it's by some financial incentives, and we'll talk more about how PIMs work in subsequent slides. So you can see here how we kind of think about these two things. One is we're thinking about the most efficient combination of inputs, and then the other one is how do we efficiently produce outputs. But there are questions and limitations to these approaches. For example, for multi-year rate plans, a common question is, okay, you can imagine a multi-year rate plan that is -- has very strong incentives for the utility to reduce its costs, but we also need to make sure that we're providing such a framework that is feasible to the utility because, really, electric utilities are the backbone of our society and we need to make sure that they're able to produce their outputs and are not under undo stress financially. And then the question with PIMs is what are or what should be the utility's outputs and then how do you measure them. And there's any number of questions, and we'll get to that later.

Spending just one more slide on traditional versus performance-based regulation, thinking about the comparison between the two, generally speaking, traditional regulation is cost based. So the utility, because it's able to file a rate application every -- you know, whenever it deems necessary, costs and revenues end up being closely linked. And that causes there to be relatively lower incentives compared to performance-based regulation. There's also questions about, you know, administrative efficiency and whether the outputs that the consumers are looking for end up being delivered. Under performance-based regulation, the goal is to disconnect revenues and costs in order to provide incentives for the utility to find cost efficiencies. That would be under, like, the multi-year rate plan category of performance-based regulation. And as a result of that approach, you have less frequent rate cases and, ideally, depending on how you set it up, lower administrative burden over time. And then on the PIMs side, you have the incentive to provide enhanced production of certain outputs.

So I suppose -- I know that we have time at the end of the presentation for discussion, but I'll pause because I've gone through a lot here and I'll ask if there's any questions based on what I've discussed so far. Doesn't look like it. Oh.

MS. TUGGEY: This is Carly. I don't have a question, but are we able to get the slides?

MS. HEALY: We're going to file the slides in the docket.

MS. TUGGEY: That's great. They're really great. Thanks.

MS. HEALY: But if you if you want to pull them up on your laptop, you could log into Teams and mute yourself.

MS. TUGGEY: Perfect, yeah.

MS. HEALY: And then you'd at least see them.

MS. TUGGEY: And I was just thinking to share with folks on our team too to help frame things up. Thank you.

MR. CROWLEY: This slide is just depicting what we view as being the status of PBR in the United States. Now, I want to get back to something I said about five minutes ago which is that it is a fuzzy line. We're using a little bit of judgment here in what we would consider to be PBR and not PBR. So someone might look at this map and say like, oh, I disagree with, you know, North Carolina or something, I don't know. But we are aware of different PBR tools in different states that are being used. And so any state that has yellow, for example, is a state that has at least one utility that has at least one PBR tool being used. And so the -- even within the category of the yellow implementation category of states, it can be a lot different state by state. So let me just say one example. So, for example, in the state of Massachusetts National Grid and Eversource both operate under -- well, in the past, they've both operated under a revenue cap plan. Massachusetts Electric, a/k/a National Grid, currently operates under kind of a hybrid plan where their O&M expenses are under a revenue cap but capital-related revenues are more cost of service based. So even within a state you have differences in how PBR is implemented. And then, you know, in California you have these multi-year rate plans that are three or four years long. And that looks a lot different from what we see in Massachusetts. And that looks a lot different from what we see in New York, etc., etc. Now you'll see from this figure that Maine is colored yellow, and we'll talk more about why that is in a minute. But just to preview, if we think back to the two categories of PBR tools, there are multi-year rate plans and there are PIMs. And PIMs are financial incentives to produce certain outputs, and those kinds of outputs include things like reliability, customer service. And so our finding in doing our work is that, because the service quality indicators that both Versant Power and Central Maine Power have are attached to financial penalties, that is considered a PIM. And, therefore, we color Maine yellow in this in this figure.

So I just gave you the preview, but I will move on and say a few things about existing PBR tools in Maine. Actually I'm going to start with the second one because that's what I just referenced which is that both of the investor-owned utilities in Maine have service quality indicators, and in both cases, those service quality indicators are tied to financial incentives where those incentives are penalty-only incentives. So there's a few categories. I think our report has a larger table that kind of goes through the different service quality indicators that our experience -- or that the two utilities operate under. So they're not necessarily the same across both utilities, but both utilities do have SQIs that have a financial incentive tied to them. So that's the PIMs side of PBR.

On the multi-year rate plan side, the distribution utilities in Maine are allowed to file alternative ratemaking plans which span multiple years and could be either forecasted or indexed. So although I think it might be the case, if I'm recalling correctly, and Andi or anyone on in the room can correct me if I'm wrong, but my recollection is that Central Maine Power has a two-year kind of agreement at the moment which --

MR. COHEN: Yeah, this is Peter Cohen from Central Maine Power. I can confirm that.

MR. CROWLEY: Okay, yeah. So that -- it's a -- it's kind of like a mini multi-year rate plan, but it's still -- you know, like I said, it's not like a binary term where it's like, oh, we flipped the switch and suddenly we're in -- within the world of PBR. But our understanding from reading the documentation in Maine is that, you know, just to pick on Central Maine Power, if you wanted to file a rate application that had more years, you could do that. And if you wanted to do kind of an indexed cap or revenue cap or price cap approach, you -- you're allowed to do that. There's no rule as far as I know that means you can't do that. So those are the tools that are available in Maine. Service quality indicators are currently in effect. Multi-year rate plans, you know, there's an example of sort of a -- just a two-year version of a multi-year rate plan, but there's the possibility of utilities voluntarily filing different multi-year rate plans that are different from that two year.

This is the proposed policy goals in Maine, and I think it's useful to look at them because when we're making recommendations, the whole purpose of the investigation into PBR is to say do the state's current rules incent the utilities to pursue business practices that align with these policy goals. So let's just take them one by one, and I would encourage you to focus on this slide when you provide feedback because this will be kind of the basis for what the recommendations are based on. So let's start with number one, promote efficient and cost effective transmission and distribution utility operations. Just as a side note, if I was a PBR planner making a regulatory framework for a state and someone said we want to promote cost effective operations for our utilities, I would say, okay, let's go back to slide five or whatever it was where we were looking at the two tools of PBR. You've got multi-year rate plans and PIMs. I'm thinking the type of tool that does this first policy goal that aims to accomplish this goal is the first one, multi-year rate plans, developing a multi-year rate plan that provides incentives to the utility. Okay, increase planning and preparation for extreme weather events and climate hazards. Promote cost effective and comprehensive responses to outages. Those two are linked in sort of a sense because outages often come from extreme weather events. Increase affordability and customer empowerment and satisfaction. Support achievement of the state's goals for increasing consumption of electricity from renewable resources. I'll just pause here and say if I was looking at those two over-arching tools, multi-year rate plans and PIMs, I would say PIMs are a tool that could aim to achieve this goal. So if you read the report, you can look at -- the state of Hawaii, for example, has renewable connection PIMs that provide rewards for the utility to connect renewable resources to the grid. Advance the state's greenhouse gas emissions and reductions goals. I feel like that sentence is supposed to end with greenhouse gas emissions goals and maybe we need to delete the word established. And advance beneficial electrification. So a lot of these are intermingled, but these are the proposed policy goals. So think about those and whether they seem to align with what you think are the appropriate policy goals for the state of Maine because these are not set in stone and they can be -- you know, it's up for a discussion. That's the whole reason we're here today.

MS. TUGGEY: I know we're supposed to hold questions to the end, Nora, but there's just -- on that one, and you had made specific reference to it as an area to focus for commenting, you prepared that for this slide, correct?

MR. CROWLEY: When you say --

MS. HEALY: -- yeah, if you're asking who prepared that --

MS. TUGGEY: I meant that it's not in the report, correct, the --

MS. HEALY: No, I think the --

MS. TUGGEY: -- find that --

MS. HEALY: -- those goals are reflected in the report --

MS. TUGGEY: They're reflected throughout --

MS. HEALY: Right, right. Yeah. Well, I think there's a -- this same list appears in the report, doesn't it, Nick?

MR. CROWLEY: Gosh, I have to -- I can't confirm that immediately, but I don't know if -- Andi, you have got your hand up.

MR. ROMANOVS-MALOVRH: Yeah, I think they covered them in Section 7.3, and we have the regulatory goals in state of Maine. And I believe they're the exact same ones we have here.

MR. CROWLEY: You're right. Yeah, it's there at page 73, yeah.

MS. TUGGEY: There it is.

MS. HEALY: And since we're just asking a few questions about this, Nick, are these ranked in a particular order or are they sort of unranked and maybe you could just speak to that?

MR. CROWLEY: I would say it -- I would say they are unranked.

MS. HEALY: Thanks.

MR. CROWLEY: But we could rank them if there's an -- you know --

MS. HEALY: I think that's what -- I think that should be a topic of discussion after you're through your presentation but yeah.

MR. CROWLEY: I would personally not feel comfortable ranking them. I would need input from the folks on the call today in order to rank them.

Okay, so now that we know what the options are or what the current state of PBR is in the state of Maine, let's look at some PBR tools for consideration. So this first category is one that's actually not new to Maine. Central Maine Power will be familiar with price and revenue caps. And this, as I understand it, is something that could still be -- either Central Maine Power or Versant Power could currently voluntarily submit a rate application that is a price or revenue cap. How it works is it sets revenue requirement in the initial rate application just like you would under a traditional form of regulation. So there's nothing new in the in the first year of the plan, so to speak. There's a rate application. There's a revenue requirement. There's rates that are set based on that revenue requirement, and that's how rates are set in year one. But then in subsequent years, a formula based on inflation and industry productivity adjusts either prices or revenues depending on whether you have a revenue cap or a price cap. Each year of the plan -- so maybe you have a five-year price cap plan, well, then the prices that you set in year one of the plan then are adjusted by this I minus X formula for year two, year three, year four, and year five. And then at the end of year five, the utility can come back in for another rate application. And so what the reason for this approach is that it allows the utility with -- it does two things. It says the utility is not able to come in for a rate application for some set number of years, and it's not able to adjust its rates based on its own costs. So that provides the utility with really strong incentives to be cost efficient, to try to reduce its costs so that it's able to retain the return on equity that it's allowed or even exceed the return on equity that it's allowed if it's able to. And the I minus X formula is really just what we call an attrition relief mechanism that says, okay, we understand that, over those five years, the utility's costs will likely increase. They will increase according to inflation and some productivity measure. So we'll adjust the utility's rates according to that I minus X formula to allow the utility the opportunity to continue to recover its authorized ROE. So the theory is that the utility operates under this price or revenue cap. It finds cost efficiencies in order to maximize profits and then re-sets its rates. And over the long run, that way of operating or that regulatory framework is supposed to provide benefits to customers in the form of slower rate escalation over time, and it provides benefits to the utility in the form of higher -- potentially higher profits if it's able to find cost efficiencies. So the customers are protected knowing that their rates won't increase any faster than the broader industry rates are increasing, and the utility takes on some risk in making that kind of promise but is -- that risk is matched by the potential for improved profit. And the goal here is to emulate competitive markets, make everything more efficient if possible, at least provide financial incentives for finding efficiencies. And so that's the theory behind price and revenue caps. I know that they're not currently used in Maine, but that there's -- that Central Maine Power used to have a price cap for a number of years.

Another thing I'll just say about price and revenue caps is that the I minus X formula is kind of the way it's often talked about. But there, in most cases, are many other letters to the PBR alphabet here. There's a stretch factor, there's exogenous factors, there's capital factors that support capital investment, and we can talk more about that if there's interest. But I minus X usually is not sufficient to provide the utility with what it needs to survive for a five-year PBR plan.

So can indexed caps be applied in Maine? Well, that's a question that I put to you, but here's our kind of assessment. There's advantages and challenges. Indexed caps, you know, the -- if the -- if one of the goals and policy goals in the state of Maine is to improve affordability, to improve cost efficiency, indexed caps can work to -- at least the goal of indexed caps is to provide those cost efficiency incentives. Now, one reason that indexed caps might be viable or feasible in Maine is that that Maine's investor-owned utilities are lines-only utilities. And that provides a little bit more in the way of feasibility because, with distribution systems, the kind of lumpy capital investments that you see in generation and in vertically-integrated utilities is a little bit smaller. Generally speaking, if you have a vertically-integrated utility that has to put in generation -- or generation investments periodically, the kind of incremental price cap approach, it's not as well fitted for those kinds of utilities. But in the state of Maine, you have lines-only utilities that own transmission and distribution. And so it's somewhat more feasible for such utilities than it is for vertically-integrated utilities. There's also past experience with price caps in Maine, and that might help -- you know, what your experience was with that can help inform whether it's a good idea to continue to try in the future.

The challenge is, of course, that Maine's LOUs are transmission owners. That means that they have large, lumpy investments that are associated with transmission. So that lumpy capital investment issue that I talked about with generation doesn't just go away with lines-only utilities. There's still, you know, lumpy capital investments, especially on the transmission side. The other thing is that there's any number of unforeseen or -- unforeseen costs or things that are outside control of the utility management that would need to be accounted for in some kind of additional factor. So I'll talk about those maybe in -- here in the next slide which are additional elements that might be included in an indexed cap.

Exogenous factors, capital trackers, guardrails like earnings sharing mechanisms or off ramps and reopeners. What are these things? So exogenous factors are things that are costs that arise that are outside of the control of the utility. So things like fuel costs. Now, in Maine, since the utilities don't own generation, they might not have to worry about that, but there's still any number of other costs that are outside of the control of the utility. Things like pension cost changes where that's really something that is based on market interest rate changes that the utility can't control. Storm costs oftentimes, insurance costs, transmission charges, things like that that are outside of the control of the utility. Rather than putting them under this price cap, most of the time, in most jurisdictions that operate with these kinds of PBR tools have a long list of these exogenous factors. And then similarly with capital trackers, almost every -- in fact, there's no jurisdiction right now that I'm aware of that operates under a multi-year rate plan that doesn't have some way of handling capital outside of the indexed cap. So in Hawaii, they call it the exceptional project recovery mechanism. There's a subset of capital projects that, if you meet this criteria, you can collect the costs for those projects. Similar -- similarly in Ontario, they have the incremental capital module which says, okay, if you meet this criteria, you can file for cost recovery for these capital projects. In Massachusetts and Alberta, they have what's called the K-bar mechanism which is basically -- I mean, what it is is it takes historical capital spending and projects the trend in the utility's own historical capital spending into the future and says if the I minus X formula doesn't give me what the historical trend predicts I will need during my PBR plan, we can collect the difference between what we get under I minus X and what the trend suggests we actually need. So it's kind of a mechanized way of saying we need capital supplement -- we need some kind of supplemental capital revenue, but we're not going to use our own costs to determine what that amount is. It's going to be -- we're not -- it's not cost of service based, per se. It's more like a formula approach. I'll also say that the K-bar approach was just proposed by Eversource in New Hampshire in its most recent rate application which is still pending.

Guardrails, earnings sharing mechanisms, I think the utilities in Maine are familiar with earnings sharing mechanisms. Off ramps and reopeners are tools that say, okay, we need to have a -- some kind of contingency if this indexed cap plan flies off the rails and something goes terribly wrong. We need a way of handling what to do about that. So an off ramp would be, okay, maybe the -- maybe there's been an extremely poor ROE that the utility experiences, way below what it's authorized ROE is. In that case -- or way above what its authorized ROE is. An off ramp would say we need to have the utility come back in and file a new rate case to re-set its rates according to costs. Reopeners are a little bit more light handed. It's -- it says, okay, there's something -- maybe there's been an ROE trigger. Maybe the utility's ROE has been too high for too many years, and we need to look at why that is. And then there could be any number of solutions which could include an off ramp to that outcome. So those are guardrails to reduce risk under a price cap or a revenue cap plan. And what you -- if you look at price cap and revenue cap plans in British Columbia, Alberta, Ontario, Massachusetts, Hawaii, they all have some combination of these of these tools.

Okay, moving on from multi-year rate plans or from the indexed cap question to PIMs, the question is can PIMs be expanded in Maine. Now, the subtitle here is utilities in Maine already operate under penalty-only PIMs. I think that's important to stress because what you -- I think we have in our report is the term PIM is not used in every jurisdiction, but that doesn't mean that they are not there. So, for example, in Great Britain they call them output delivery incentives, ODIs. In Hawaii, they call them PIMs. In British Columbia, they called them targeted incentives, and in Maine you call them SQIs. The definition of a PIM is any -- well, it's any kind of financially -- financial incentive mechanism that provides the utility with a reason to produce certain measurable outputs, and usually that means that the financial incentive and threshold are predefined before -- you know, it's not like the regulator comes in after the fact and is able to say, well, you did badly so I'm going to make my own judgment about what kind of penalty that means. PIMs, by definition, are set in advance so that all parties know what kind of target needs to be hit and what the penalty or reward would be for hitting that target. So by that definition, Maine has what are called penalty-only PIMs, but PIMs can also be reward only. They can be symmetrical which means they have both a reward and a penalty. So, for example, both New York and Hawaii have reward-only and symmetrical PIMs. One way of thinking about whether to have penalty-only, reward-only, or symmetrical PIMs is to think about does the output that we're considering for this metric -- is it considered to be sort of a traditional output that the utility's already expected to produce and it's sort of contained within its rates. So, for example, oftentimes reliability in the form of a SAIDI PIM or a SAIFI PIM, those are oftentimes penalty only because they're sort of expected of the utility. And if the utility's expected to produce it, it should be collecting the revenue it needs to produce it. And if it doesn't, then it gets docked some amount. Whereas if you want to think about what might be a reward-only PIM, a reward-only PIM would be something that the utility hasn't in the past been expected to do. So, for example, connecting DER -- connecting distributed energy resources. That might not be something that the utility has sort of a traditional expectation of doing. And if the policy goal is to incent DER connections, then the utility would be rewarded for doing something that it's not sort of traditionally expected to do. It has a financial reward for that. Or, like, reducing greenhouse gases, for example. That might be something that would be a reward-only PIM. Or maybe, you know, you could make an argument for making it a symmetrical PIM. So that's the way that we think about deciding between whether or not to have a penalty-only or a reward-only PIM.

Other jurisdictions have introduced PIMs to encourage investment and action to meet policy objectives similar to Maine's policy goals. So our report contains a few examples of that from New York and Hawaii and maybe some other places. But it's also important to consider that Maine doesn't have -- every jurisdiction is different. Maine does not have the same control over -- or I should say the IOUs in Maine don't necessarily have control over the same outcomes such as greenhouse gas emissions as a utility like Hawaiian Electric Company which is an island utility that owns its generation. So the -- a utility that owns its generation has much more ability to control what its greenhouse gas emissions would be, whereas the distributors in Maine, maybe they don't have quite as much control over that.

Okay, let's talk about the advantages and challenges of PIMs. The advantages, of course, are that we have this set of policy goals, we have an idea of maybe what the utilities should be producing as outputs, and PIMs provide an incentive for the utilities to produce those outputs. They also -- they do that work efficiently. So it's -- it tends to be more efficient to provide a utility with a financial incentive than it is to have a mandate. And the reason is that the utility -- if the PIM is properly designed so that the reward or penalty amount is based on the value to consumers that is produced by that output, then the utility has the ability to make a judgment about whether -- essentially, whether it wants to find the efficient way to produce those outputs or whether it wants to essentially remunerate its customers for not producing that output is kind of the economic way of thinking about it. There's also -- tends to be more flexibility and transparency with PIMs. The flexibility, again, in the sense that the utility has the ability to make its own economic decisions about what is the right and appropriate level of output to produce of whatever certain output we're looking at. And then transparency, of course, is because that the utility has -- if you have a PIM, the utility is going to be publishing a metric that the -- that it either is able to meet at some threshold or it's not meeting. And so everyone's able to look at that published metric and see has the utility achieved what it set out to achieve.

Okay. So those are the advantages of PIMs. The challenges are plentiful with PIMs. And that doesn't mean that they're not, you know, a good idea in some cases, but we need to be aware of the challenges. So there -- there's a lot of design complexity. It's difficult to quantify the performance outcomes and set the appropriate rewards and penalties. Really, the appropriate reward and penalty should be based on the value to customers. So there needs -- there should be, ideally, some form of cost benefit analysis involved in the design of a PIM, and that can be expensive. And also challenging just in terms of feasibility. Limits to timely access to metrics, sometimes there's a lag between when metric is met and what the utility gets in terms of its remuneration, and that can create a potential mismatch between incentives. Accounting for external factors, of course, as we all know, there are many things that affect utilities that are outside of the control of the utility, and having its revenue based partially on things that are outside of its control is -- you know, there -- there's risk there and maybe not the best idea. Then there's unintended consequences. So whenever we think about providing financial incentives for one particular output, the utility may then have an incentive just to focus on producing that particular output, and that might be to the detriment of other outputs that are also important. And then there's finally a risk of gaming or manipulation by utilities. If the utility knows, oh, I need to answer my phone calls within 30 seconds, it'll get really good at answering these phone calls within 30 seconds. But that doesn't necessarily translate into better customer service depending on how -- you know, how subsequent action is taken. So those are the challenges. I mean, that's just a list of some challenges. We talk more at length about it in our report.

So here we are. We're on our last slide of the presentation which is observations and next steps. So observation number one, Maine IOUs face service quality indicators that meet the definition of PIM. So right now, the state of Maine has PBR tools in place as we see it. And the state's alternative regulation option allows utilities to voluntarily file multi-year rate plans. So there's a -- there's potential there already. It -- it's worth noting that other jurisdictions like Alberta and Ontario require electric utility -- electric distribution utilities to operate under some form of PBR. So in, for example, the state of Massachusetts, Eversource and National Grid, they are able to file voluntarily whatever PBR plan they want, but that's not always the case. I think it's -- you know, Australia, Alberta, Ontario, and Great Britain that we looked at, those jurisdictions require their distributors to operate under some form of PBR. So that's just worth knowing. And I'm not necessarily one to advocate for that approach, especially in a state like Maine which has only two distributors. I think the reason that those jurisdictions operate that way is that there's a lot of distributors and it's just easier for the regulator to handle. I mean, if you're familiar with Ontario, there's, like, 55 distribution utilities there and they can't handle the kind of frequent rate applications that they might have to deal with if they all weren't operating under PBR. So they all -- the jurisdictions where PBR is mandated, generally there's a lot of utilities in those jurisdictions. And then the final bullet point on this slide is Christensen Associates will provide recommendations following the stakeholder engagement meeting. And so if you look at the report, we have placeholders right now where our recommendations will go, and the goal of the presentation here is to set the stage for discussion on what will end up being in those recommendations.

So that, I think, brings us to the end. I will also say that we have substantial appendix material that we can go through and reference maybe as we discuss. A lot of it is what's going on in other jurisdictions. So Ontario, Alberta, British Columbia, Hawaii, Massachusetts, California, New York. Some things going on in the UK, Australia, New Zealand. And then we have a few slides on more detail on some of the tools that I talked about earlier with regard to indexed cap PBR. So we have what different jurisdictions do in terms of capital funding, more on K-bar because K-bar is very interesting and more complicated, and that -- I think that's it. So I flipped through these quickly, but I just wanted to show you what's there in case it's helpful for discussion. So I'll pause there, and, Nora, if you want to take the mic and facilitate discussion.

MS. HEALY: Great. And so I'll just mention again we'll -- we will have all those slides in the docket. And, Carly, just to be clear, were you looking for them to be emailed now or do you have people --

MS. TUGGEY: No, just in general. I thought the slides were helpful and it would be valuable to share with folks who are working on these.

MS. HEALY: Yeah, no, that's what we intended. I just didn't -- as I've thought about it, I thought, oh, maybe someone needs to -- needs it right now that's (indiscernible) that's not on. All right, great. And then another thing I wanted to note, there was a little discussion I think that asked where those draft sort of policy goals came from, and there is proposed legislation in L.D. 2172. And so those goals were reflective of that proposed -- the draft goals were reflective of that proposed legislation. So just wanted to let folks know that.

So I think now we can open it up for, you know, comments and questions and discussion. And as we talked about, I think the first place to start really is with those goals. And, Nick, maybe you want to flip back to the slide with the goals on them, the seven goals. And as Nick indicated, they aren't ranked. You know, one thing the Commission would like to get input on is whether those goals capture the right goals for Maine utilities, and, if so, if there are things missing from those goals or things that should not be included there. We'd like to get some input on that, you know, today and in written comments. And Pat has a question. So Commissioner Scully?

MR. SCULLY: Hi. This may be a question that you can answer, Nick, or it may be that others in the room can answer. It's more a history question, but my recollection, and I think you reference this, is that for a number of years CMP operated under a more complex alternative rate plan that was multi-year that was kind of based on a formula somewhat similar to the formula that you presented. I was not a Commissioner at the time, and at some at some point in time, either the Commission moved away from that or CMP moved away from that. And I'm wondering if anyone knows what the rationale was for moving away from that type of multi-year alternative rate plan.

MR. COHEN: This is Peter Cohen from CMP. I have the distinction of having been here when we had the ARPs and when the last ARP ended. And so the company filed a request for a third ARP, and at the time, the feeling was is that we had had two ARPs and I think one was five years and one was seven years. And the impression, as I, a utility employee, got was that it was felt that we needed to take a break from a price cap mechanism and return to, you know, the single rate year practice. And then that continued for a number of years until Central Maine Power, in its last rate case, proposed a multi-year rate plan. And that was consistent with our belief and really consistent with a lot of the messages in this document that that is the right type of rate plan for a utility. And price caps are helpful, but they're complicated and they're hard to get started. And so we felt starting off with a multi-year rate plan was, you know, getting back into the right direction without introducing something that, in relatively recent history, had gone away.

MR. SCULLY: Thanks, Peter. That's really helpful.

MR. DAVIDSON: Yeah, and maybe, Pat, I'll add a little bit to that. Like Peter, I was here as well. And I -- everything he said was right on. I think the other sort of piece to that was we, as staff, were speculating that we had gotten maybe maxed out in our efficiency improvements with the utility. And -- at that point in time, and we questioned whether we could get any further efficiency going forward.

MR. COHEN: No, I --

MR. DAVIDSON: And that's on top of --

MR. COHEN: I agree with you, Derek, because I do remember this X factor was getting smaller and smaller, and then it flipped to be a negative. And I think we changed the name to a Z factor because there was -- this was occurring at a time when there was a transaction that occurred. And so there were these benefits that could be obtained, and that was factored into the offset and the stretch factor. So the S and the formulaic on, I think, it was page 16. And that went away after they were achieved.

MS. HEALY: So the transaction you're talking about a reorganization was --

MR. COHEN: This was a transaction between Central Maine Power and the Energy East Company.

MS. HEALY: Okay.

MS. TUGGEY: Nora, I have just a high-level question for Christensen. When you include the summary tables and the finalized brackets, will those be -- I mean, obviously this is complex and there's a range of ways to do this with pros and cons depending on where you fall on the spectrum. Are you planning on making sort of a, you know, first order recommendation or an if this, then you get this but you don't get this. Like, how are you planning to approach the recommendation component of it, if you know?

MR. CROWLEY: Yeah, that's a good question. We recently did work similar to this in another state, and most of the recommendations that we provided were more on the if this, then that sort of thing. So, for example, if you go to the portion of the report that has -- it's the indexed cap portion of the report. There are many tables on -- like, Table 4 point -- 5.4 or 5.5, 5.6. It's, like, how do you set an inflation factor? How do you set an X factor? How do you set a stretch factor? All that stuff is -- the recommendation is likely to be something like if an index cap is filed, the inflation factor should be set according to, you know, this criteria. If an indexed cap is filed, the X factor should be based on a total factor productivity study, that sort of thing. So that's some of it. I think in other parts of the report, there might be more concrete recommendations. But a lot of it, I anticipate, will be, you know, something like if this PIM is adopted -- you know, if some PIM approach is adopted, these are the criteria that you should be following when designing the PIM, that sort of thing.

MS. TUGGEY: That's really helpful. Thank you. And I asked just because, as we proceed, there's a lot of work that I think is going to play out in this docket. To the extent that we can be, you know, listening and taking these recommendations into how we present things to the Commission, it can be helpful. So it's helpful to know that you might give a if this, then this. Then we can put context around any proposals we make.

MS. CHAMBERLIN: So I was looking at the customer focused one, the increased affordability and customer empowerment and satisfaction. And I was comparing it to the Ontario principle which uses slightly different language. Let's see if I can find it. A customer-centric approach, encouraging expanding opportunities for customer choice and participating in all appropriate aspects of utility system functions. I think that gives a little more definition. I think customer empowerment is kind of vague. I don't think that's specific enough to really be a goal. So I like the idea of having, you know, encouraging customer choice and participation. That gives a little more specificity in what we're looking for on the customer end of it.

MS. HEALY: And I'll just note that with Susan Chamberlin from the OPA. So -- and just a reminder to folks, just mention your name at least. Thanks.

MR. COHEN: So this is Peter Cohen from Central Maine Power. One of the things that's not on here is the word safety. And that's a very important concept for our utility. So, you know, opportunities to introduce that might be item number three, cost effective comprehensive outage restoration. But there's a lot of safety involved in that that we think is really important to get documented. Because it's one of our goals as a company when we think about --

MS. HEALY: Yeah, and I think sometimes we think of that as a given --

MR. COHEN: You think of it as a base.

MS. HEALY: -- and we don't acknowledge it as a key goal, but it's obviously fundamental, yeah.

MR. MARSHALL: Could I ask a question on the policy goals? This is Brian Marshall from the OPA. So one through four, you know, I think you could debate whether, you know, traditional cost of service or some kind of PBR or incentive mechanism makes sense. And there's really no question that those are, you know, specific goals for the regulatory tool. For five through seven, I guess there's an initial question whether this is something that the utility has direct, you know, control over or if the utility is the best positioned entity to address. I'm not questioning that they're important goals, but, you know, for example, we have a renewable portfolio standard that applies to the suppliers of electricity. We have Efficiency Maine Trust which is a separate state entity. And for something like beneficial electrification, is that something that might be better addressed through rate design rather than the specific regulatory structure? So is there some analysis needed to determine, you know, not whether the goals themselves are important but what contribution do the utilities make towards those goals? And is there actually some other entity or entities that should be tasked with addressing them? Or could they just be addressed through the design of rates themselves?

MR. CROWLEY: Yeah, I think that's a great question. And if you look at number six, that is something we mentioned also in this -- in these slides which is that in some places that have PIMs, it's easier to incent the utility to do something with regard to greenhouse gas emissions than it is maybe in the state of Maine because of the structure of the industry in Maine. So, yeah, I think maybe that's an argument for ranking the different policy goals because, you know, I could imagine that we design tools with some of these latter items in mind but that they're not necessarily the focus because of the reason that you just said which is that maybe it's not quite within -- fully within the utility's control. And I suppose I would ask the IOU representatives if they have thoughts on what tools could be used to address some of those, like, six and seven items. But I see that there's a hand up.

MS. HEALY: Yes, go ahead, Carrie, Commissioner Gilbert.

MS. GILBERT: Yeah, hi, this is Carrie Gilbert. And when I was looking at the policy goals, one additional metric that people often suggest to us is a metric around interconnection. And I was trying to figure out where interconnection would fit into the policy goals, and I guess it would be in the last three because interconnect -- mostly we're talking about interconnecting renewables or interconnecting load. So I don't know if that points to including them, but I do agree that it's a little tricky because, as you said, the RPS is the tool that, I guess, in state procurements that we're using to meet the state's goal for increasing consumption of electricity from renewable resources. And the utilities, because they don't supply, they're not really involved in that. But they are involved in the interconnection process which is -- which seems to be the one metric that people have consistently suggested we should be adding. So I don't know what that means about leaving them on, but --

MS. HEALY: Or perhaps that's suggesting more narrowly tailoring them to reflect the things that are within the utility's control.

MS. GILBERT: Yeah.

MR. MARSHALL: I could add a --

MR. CROWLEY: Yeah, I can -- oh, go ahead.

MR. MARSHALL: I was just going to add a comment that I agree, and I agree with Commissioner Gilbert's statement. And maybe rather than having five, six, seven as the sort of broad and somewhat vague articulations of policy, you have a very specific one on interconnection. And, you know, whatever your goal is related to interconnection, you want to reduce the time it takes or the expense of that, you know, make that the goal rather than something kind of vague and hard to understand and very broad, like reduce, you know, greenhouse gas emissions or advance beneficial electrification. I think the more specific the goal is, the better and the easier it will be to implement.

MR. COHEN: This is Peter Cohen, CMP. So I agree with Brian strangely enough. And when I read five, six, and seven, I -- one word came to mind which is infrastructure. And that's what I do, right? And so I need to have the infrastructure that helps our state achieve these goals. And this is one of the reasons why I believe a multi-year rate plan of duration is important because the planning for this infrastructure is time consuming and it's expensive. And then actually executing on it is kind of what our company does, right? We are less of a rate case company and more of a public utility that builds things and makes them safe and reliable.

And I do agree with Commissioner Gilbert about the interconnections that having a metric there too would help to address these. And, you know, Brian's right, we can't solely handle the achievement of climate change goals as Central Maine Power. But we can participate in them, and our ability to participate can be encouraged based on the type of regulation that we're operating under. And that's why, again, we felt it was important for a multi-year rate plan so we could focus on that. And I think -- actually I don't think, I am certain that

CMP will continue to believe that way and it'll be demonstrated in future filings.

MR. SIMMONS: Kiera has a question online if -- all right, sorry.

MS. HEALY: Go ahead, Kiera. From the Governor's Energy Office.

MS. REARDON: Thank you. Kiera Reardon. Just listening to this conversation, I think it's a really exciting moment here because all of the things that we're talking about now I feel like are coming together nicely with the climate plans that were just submitted, and CMP's presentation is on this afternoon, and the integrated grid plans that are under development and these proposed policy goals. So I'm actually wondering if there -- I would welcome feedback from the group on if there's merit on sort of zooming out and finding a way to weave the concepts we have under development in the integrated grid plans and what I've heard from the Commissioners through deliberations about using those to drive rate cases and what we're looking at here in this docket because it feels like we're just really on the cusp of having a lot of really neat, new, exciting tools at our disposal. And if we could institute them all at the same time and in a cohesive way, I think we'd be all the better for it. So not really a question, more of just a general statement for reaction.

MR. SIMMONS: David, did you want to say something?

MR. LITTELL: Just to respond to a question. David Littell for Versant Power. To respond to the question that was posed, I guess I'll respond with a question which is Brian raised the question of how much impact the utilities have on five, six, and seven which is a good question. But my question is what's sort of the envisioned outcome of this proceeding? Because those are general statements, and Brian sounded like he was diving right down into to designing a PIM. And I don't know if the outcome of this is going to be very specific PIM recommendations or if it will be a general concept with some illustrations that leaves room and invites the utilities to file and make specific suggestions with what those should be because the -- I mean, the detail here is that PIMs are designed to achieve very sort of specific outcomes. And you need to think those through and you need to think through the data, right? And what data you have to measure it. And you may very well conclude that we need better data to have that discussion. So we may do a monitoring-only sort of PIM for a while. That can be one outcome. And my last sort of related comment is not to confuse tracking and reporting with causation. Because, I mean, you could jump there if you're talking about either rewards or penalties, but sometimes you want to track things when the utilities may play an important role and Efficiency Maine Trust may play an important role and the Governor's Energy Office may play an important role. And then you -- you know, you can have a discussion on whether it's appropriate to have an incentive built in there, but you still may want to track them because they're important for the state. And the utilities are in a good position to do that tracking. So I just -- I throw out a bunch of related thoughts that I guess would come back to my point is I didn't envision, but obviously we're -- this is an initial discussion, the outcome of these being very specific PIMs that would be mandated but rather sort of goals with examples. And that -- so pose the question (indiscernible) feedback.

MS. HEALY: Well, I'll just -- and I know, Commissioner Gilbert, you have your hand up. So I certainly will let you speak, but I'll just note that this is an inquiry. It's not an adjudicatory proceeding. So I don't think we would be ordering anything out of this particular docket. But Commissioner Gilbert?

MS. GILBERT: Yeah, I actually -- I don't have a good feeling of the outcome of this docket either, but I think Nora's characterization would make sense to me. But I just wanted to echo Kiera's statement about tying some of these different dockets together. That's something I sort of hunger for. So I don't have a good idea of how we do that, but it does seem that the goals we're thinking about here should, you know, maybe tie to some of the priorities in the group plans. I think they're probably consistent, but anyway, I liked that idea. So I just wanted to say that. Thanks.

MR. DAVIDSON: And maybe I'd like to react to David's point because I think it's a good one. I was going to bring it up, is I think -- regarding specificity for the goals, I mean, I think what we're envisioning is these are going to be goals that are going to guide the Commission when it's evaluating what sort of a performance-based ratemaking plan might work for a utility, and the specificity would come in the PIMs. And I think it would be dependent on the utility as well as, you know, what we were trying to achieve. So with the goals, I think from my perspective, from a staff perspective, I want to know what are we --what is important to the state and what are we trying to achieve through this performance-based ratemaking plan. Then we can get into the specifics maybe about -- you know, as far as what sort of PIMs do we have to have in order to sort of -- to get us there. I think that's what I'm envisioning coming out of this process.

MR. SIMMONS: Yeah, and I think to add, you know, the point of this stakeholder meeting is to have this conversation, get the comments from the participants so that Christensen Associates can kind of complete the report that they've been working on. And I'll let Nick kind of talk about that recommendation part again that, you know, from what I've heard, it's going to be more if you go down this road, you want to consider these things, or if you're building a PIM, these are the considerations that you should be looking at. And I don't think, to David's point, we're getting -- the intent isn't to design the PIM, kind of do the homework to figure out what -- you know, what the target should be. And, you know, I don't know, Nick, if you need to chime in and talk about the -- kind of the report and what you see it as, but I'll give you the opportunity.

MR. CROWLEY: No, I think that is a fair characterization of the plan. So you wouldn't expect from our next draft to see PIMs that we would recommend necessarily. But we might provide guidance on how to design them, what PIMs exist in other jurisdictions that have been used to address some of the policy goals that we see here. And then I'm -- I just wanted to say on the point -- on David's point and then also -- I don't know who was talking over there on the far side of the room, but with regard to these kind of policy goals, if we look at Appendix C of the report, I have different PBR principles from different jurisdictions. And I view the policy goals as somewhat similar to what we see in Appendix C in these other jurisdictions where there's more over-arching goals that are used as guideposts for what tools then get used. And so to give a specific example, just yesterday -- I think it was just yesterday a discussion paper was published in Ontario where the Ontario Energy Board has made recommendations for what PIMs they might be introducing to the province. But each of those

PIMs is sort of categorized under -- or has a set of policy goals that it aligns with. So I think there's, like, for example, a system utilization PIM they're calling, and that system utilization PIM is aimed at, for example, addressing affordability for customers and cost efficiency for the utility. And so it's not necessarily that the policy goals are creating specific examples of what PIMs are needed but rather that the PIMs adhere -- or are aimed at addressing certain policy goals if that makes sense.

MS. TUGGEY: And maybe I'm more comfortable with this than I should be based on comments from my peers, but I'm actually very comfortable with what we're doing here in terms of talking about these ideas and the approach that it sounds like they're going to take in terms of there -- the -- there's the spectrum, and then here are the things, you do this, you get this; you do this, you get this, you might not get this. I think where I get a little uncomfortable is that the Commission is only bound by statute. So it's bound by the policy that's established in statute. So to the extent that these policy goals -- if there's an expectation here that the inquiry is going to lead to a set of policy goals that bind the Commission in terms of how it frames this, that's where I would get a little uncomfortable. I think if the point is to say, like, we're all talking about this in the same way, here are the kinds of goals that these PIMs could achieve and they're tangentially related to statute, that's great. But I just don't want to be left thinking that the policy goals here are going to bind the Commission in anyway with regard to the PIMs. That was the only thing that started to get me nervous --

MS. HEALY: No, and I can't read all the handwriting on the wall. But to be clear, I mean, these were policy goals that were reflected in proposed legislation, and there will be a report back to the legislature. So, you know, I -- again, I don't have a crystal ball, but I don't want to suggest that the legislature couldn't decide something like this that would constrain the Commission. But I think this is an opportunity for us to help inform that not in front of the legislature. So, you know, I don't -- others might have -- want to add to that, but -- and I'm just speaking for myself personally, but I think, you know, again, the topic of, you know, sort of what's missing from this -- and I know you --Peter, you mentioned safety, but if there are other important topics, I think those are the kinds of things that would be helpful to get out. And I think also the discussion about -- you know, and we've talked about this in cases, you know, for a number of years now, the goals that are less in the utility's control and less, you know -- but are important to the state need to be sort of tailored. And we do that in rate cases to some extent. But I mean, I can think -- you know, when we were talking about five, six, and seven, certainly there are limitations, and interconnection's an important one. But I've also seen, you know, utilities play a role in education. And, you know, obviously rate design is an issue that was worked on out of last CMP's last rate case and is going to continue to be worked on. And to Peter's point, there are infrastructure things associated with rate design, you know, billing systems that need to be addressed. So, you know, I think, again, just speaking for myself, but I don't want you to be left with the impression that this isn't going to go back to the legislature in some sort of form. But (indiscernible) after that I think --

MS. TUGGEY: Thank you.

MS. HEALY: -- guess about.

MR. BURNES: So I want to go in a little bit more detail of where Brian was going. This is Ian Burnes. I'm with Efficiency Maine Trust. We're the independent administrator of demand management, energy efficiency, and beneficial electrification programs in the state. And as that introduction, I think you might know where I'm going here. I think to the extent that this is a guide to future rate cases and it is a guide to the legislature on what the PUC's priorities, I would urge you to remove the elements of the report that are not within the control or the statutory authority of the utilities. And I think I'll just put three examples here. You have multiple examples of demand response programs. We're running the demand response programs. I just don't want to send the message that it's an expectation. There are a number of best practices from other utilities. We recognize we're a unique state in that there is an independent administrator of all of these things that are outside the utility. So I just hope that the final report will reflect that so that we can avoid any future confusion. This is not to say that there isn't a role of the utilities in assisting. In fact, when it comes to demand response programs, like, we rely on them for data. The prompt and accurate, you know, sharing of that data is important to us for how we run our programs. So it's not to say that there isn't a role, it's just it doesn't really lend itself to the same level of -- you know, it's not a three basis point increase like they have in Illinois as your report reflects. Like, it is a minor transaction that takes a couple of hours.

Another thing that I might say is, like, we've talked about interconnection, and Efficiency Maine Trust works on interconnection with batteries. And we had actually a real success in the level three interconnection process in which we -- actually, within a month, CMP permitted two major battery installations, and that was a real success story. But unfortunately, those battery projects sat for over a year at ISO New England, from my humble opinion, for absolutely no reason. And CMP was an advocate for us to try to figure out how to make that process go faster and probably, without their intervention, would not have gone faster. But if we -- when we get to a level of specificity, I think we need to make sure that we're reflecting that we're within a regional context for anything that's going to be interconnected over five megawatts. And these were -- actually these were over a -- these were -- it didn't even meet that. These were behind-the-meter projects, non-exporting projects under five megawatts that got swept into cluster studies. So it's just to say that it doesn't lend itself to a real clean --

MS. HEALY: (Indiscernible).

MR. BURNES: Yeah, I mean, there's just -- you get to fractals, and all of a sudden, like, I wouldn't want to hold CMP responsible for that delay and now unfortunate, ultimate demise of those two projects.

And the third one I would say is mention of the non-wires coordinator process. Again, this is an example of a place where Maine has chosen a very different policy. Not to say that there isn't a real role for the utilities to give us timely, accurate data to allow the thing to happen. But it doesn't lend itself, again, to sharing the savings of an NWA because of the policy practice that we have here. So to the extent that this could become a guide to legislators and people will be looking to this and I think that there is a lot of interest in it, I really urge you to be very careful in the way that you frame best practices from other regions and have them reflect the unique policy environment of Maine. And I don't think that the current report meets that standard. And I think there are some discrete -- there's lots of good stuff in here, but I wouldn't want to see what we have published in this docket right now as an example because it does not reflect that.

MS. HEALY: So -- and just to kind of paraphrase here, you're saying it's sort of missing the nuances of the fact of how you would actually maybe constrain to apply these in Maine because certain other entities have responsibility for things.

MR. BURNES: Yeah.

MS. HEALY: We talked about that in terms of generation, but yeah.

MR. CROWLEY: So --

MR. BURNES: Yeah, I mean, and -- yeah, go ahead.

MR. CROWLEY: Ian, appreciate that feedback. I also want to say please provide, in as much detail as you're willing to provide, written feedback because if you have specific examples, that would be helpful for us to make sure we're addressing it in the next draft.

MR. BURNES: Will do.

MS. HEALY: And, Andi, you had your -- I think you might have had your hand up at one point. I don't -- and maybe you have moved on, but if you did want to ask something or say something, please do.

MR. ROMANOVS-MALOVRH: Yeah, I just wanted to say, I know, Nora, you mentioned not to use the chat feature, but I'm just going to post a resource that Nick referenced previously when talking about Ontario if that's all right.

MS. HEALY: Yeah, that's okay. Go ahead, do that and people can share it. And then I think we'll just ask you to put that hyperlink into somewhere, maybe an appendix to the slides, and then we'll file it in the docket so that everyone has the benefit of that in the docket.

MR. ROMANOVS-MALOVRH: Sounds good.

MS. HEALY: Okay. It's about 10:38. So why don't we take a break? I assume people want to continue the discussion at least a bit more. Or maybe I should just ask. I'd like to think we could continue the discussion more. I mean, I -- there -- there's some more topics on my mind, and I think staff has some other questions. So hopefully, people will come back after the break, let's put it that way. We'll take a 15-minute break, and -- maybe we'll take a little bit more than 15 minutes. We'll come back at, what is it, 10:55, right? Is my math, right? Okay, great, we're on break.

CONFERENCE RECESSED (May 16, 2025, 10:38 a.m.)

CONFERENCE RESUMED (May 16, 2025, 10:55 a.m.)

MS. HEALY: -- 07, and I think staff has a few questions type comments.

MR. SIMMONS: Yeah, so I wanted to bring up kind of Ian mentioned, like, the interconnection experience that they had with CMP and the batteries. And, you know, with the interconnection, there are two phases, right? There's what's in Chapter 3 -- our Maine Chapter 324 which is the interconnection process, and the local utilities have timelines and requirements under that rule. And then the second part of that process is that if it's a certain FERC jurisdictional circuit interconnection, then there would be a regional process at the ISO New England. And given the example that Ian provided, you know, developing some sort of PIM associated with Chapter 324 which the local utilities have full responsibility for, you know, that seems like a way that you could do that. But you penalize the local distribution companies for the delays associated with the more regional process. Or even, like, the outcome that he referenced, the two projects didn't come online. So I guess the question would be, you know, is that kind of the best practice that you see in other jurisdictions where you develop the PIMs kind of to the limit that the utilities do have authority to act? That was directed to Nick and his team I guess, but, you know, if others want to respond, that would be fine too.

MR. CROWLEY: Well, I will just speak sort of generally to best practices for the design of PIMs is that you want to design PIMs that are associated with actions that the utility has control over or outcomes that the utility has control over. And so when -- if this particular category of outputs was something that was a priority in the state of Maine, just because it's a priority doesn't necessarily mean it's appropriate to have a PIM do the work. Because if it's outside of the control of the utility, then it's really not appropriate to be putting rewards or penalties on the outcomes. Does that answer the question that you're getting at?

MR. SIMMONS: Yeah, I think generally, and that kind of brings me up to another question. You know, just because we have these priorities that are listed, it's not the expectation that every priority has some PIM or other mechanism that would kind of get -- you know, provide outcomes that support those policies. Is that kind of your thinking?

MR. CROWLEY: Yeah. Yeah, that's just one of the -- like, the policy goals are just one guiding -- they're just one guidepost for the design of some kind of regulatory framework. It doesn't necessarily mean that we're going to be able to find a PIM that adheres to every single one of those seven different policy goals.

MR. DAVIDSON: So, Nick, this is Derek. I've got a question regarding the policy goals. Do other jurisdictions tend to prioritize those goals? And what are your specific thoughts about the helpfulness of prioritizing the goals?

MR. CROWLEY: I would say -- so I've worked -- in the jurisdictions that I've worked -- and I'll -- so let me think specifically about Alberta. Alberta is a jurisdiction that has price cap regulation for the electric distribution utilities and revenue per customer caps for the gas distribution utilities. And in the evidence that is filed by the utilities and intervenors in their rate applications and in their PBR proceedings, there is an expectation that when an argument is made, you tie it back to a PBR principle. So there is, I would say, emphasis on a to the principles that are set forth in that province. And I think that's also the case in British Columbia. And I think it's maybe a little bit less so in -- well, I see -- I feel like I'm -- I don't want to make judgements that would come back to bite me, but it's maybe a little bit less so in other places I'll just say. But usually the idea is, okay, if we're going to craft a regulatory framework, let's, at the end of each tool that we're describing or proposing, describe how it adheres to the principles or, in this case, the policy goals.

MS. HEALY: Have you seen other jurisdictions rank those goals?

MR. CROWLEY: I have not, no.

MS. HEALY: Or not? Yeah, and --

MR. ROMANOVS-MALOVRH: I can maybe --

MR. CROWLEY: Go ahead, Andi.

MR. ROMANOVS-MALOVRH: Yeah, I know one of the jurisdictions we worked in is Indiana, and they have this five-pillar approach. And in our conversations, the impression I had is that they explicitly did not want to rank those. And in this case, the five pillars -- I might not name all of them, but they're akin to reliability, resilience, affordability, and so forth. And one of them is also environmental. And they've said that they explicitly do not want to rank them because they want to make sure that, in the rate applications, utilities think about all of those goals at the same time. But that -- not saying that, you know, that's the way Maine should do it. Just as an example.

MS. HEALY: Nick and Christensen, could you talk a little bit about storm costs and storm recovery and how other jurisdictions might have treated those under performance-based regulation?

MR. CROWLEY: Yeah, so when thinking about storm costs, I think we're thinking in the category of multi-year rate plan PBR. So something like you're out -- you're not able to come back for a rate application for five years and a storm happens within that five years, how do you handle that in terms of revenue recovery. The -- it differs by jurisdiction. So in Alberta and Ontario, these are two jurisdictions where the utilities are under price cap regulation. The storm costs are recovered under the Z factor. The Z factor, I really didn't spend much time on -- in this presentation on the details of how price caps and revenue caps work. We could talk -- we could have a day-long talk about how to design a price cap and all the work that goes into each one of these different letters. But when we look at the adjustments to the price cap on this slide and we look at Y factors and Z factors, Z factors are just -- they're just cost recovery mechanisms that the utility can file on an annual basis with its annual PBR filing to say some cost occurred this year that was way outside of my control. Usually Y factors are ongoing costs like flow-through type costs. Z factors are one-time events, and storm costs could be categorized as Z factor costs. And that's how it's handled in Alberta and Ontario. In Massachusetts, they do it a little differently. They have storm -- well, I should say Eversource, I'm thinking of Eversource specifically. I don't recall offhand how National Grid does it, but Eversource has a storm fund, and that fund is collected as, like, a rate rider to customers up to a certain limit. And then once that limit -- which is, I think, 30 million, and once the utility has 30 million in the fund, then it either stops collecting or it starts returning some of the collected funds back to customers. And that fund has a bunch of different rules around it, but the idea is that they have essentially money set aside in case a storm occurs. So they don't handle storm costs through Z factors in Massachusetts, but those are two ways of doing it under these multi-year rate plan approaches. I think as -- I mean, my guess is a Z factor is the more widely used approach. It's just like if a storm happens, the utility's allowed to file information on an annual basis saying we incurred these costs as a result of the storm, now in rates over the next couple of years, we are asking for the ability to recover those costs.

MS. HEALY: Can you also talk a little bit about, you know, affordability as a goal that's reflected in those draft goals and what other jurisdictions have been doing to try and promote that goal in performance-based ratemaking?

MR. CROWLEY: Yeah. I would say going back to one of the first slides, this one, on what tools we are trying to use to incent certain outcomes, multi-year rate plans tend to be the tool that's used to try to incent cost efficiency. And cost efficiency ultimately flows through to customers in the form of improved affordability relative to traditional regulation if designed correctly. So if designed correctly, the multi-year rate plan incents cost efficiency which then ends up helping customers. How does that happen? Well, what you have is a utility that has improved efficiency to reduce its costs over time. And then when it comes in for its next rate application, the theory goes, it has a revenue requirement that is lower than what the revenue requirement would have been if it had been operating under a traditional regulation. Why is that? It's because the utility has a rate stay out period, and that rate stay out period is essentially providing the profit motive to cut costs as much as possible. And so the question is is that theory that affordability will improve over time, does that actually have any evidence in the empirical world that we live in? And we've seen empirical results that demonstrate that that theory is true.

MS. HEALY: Yes.

MR. CROWLEY: And the -- yeah, so the answer is it's very, very difficult to ever know for sure whether a certain regulatory framework is the reason for improved affordability. So that's kind of the caveat at the outset, but there have been studies. So -- and we have reviewed a number of these studies from different parts of the world, not in the U.S. because most jurisdictions in the U.S. don't really operate with what we would call, like, a pure price or revenue cap. Massachusetts and Hawaii do, but they're pretty young, whereas Ontario and Alberta have been doing it for a long time, and some countries in Europe and Australia, for example, have been doing it for a long time as well. So the data is more readily available in other countries, and what we have seen is that it does seem to be the case that jurisdictions that operate under price caps or revenue caps have slower rate escalation for customers. I authored a paper in Utilities Policy, I think it came out in 2021, looking at a comparison of Alberta and Ontario utilities that operate under price caps with a set of utilities that do not operate under price caps as, like, a sort of quasi-control group, and found that over the period of time between the year 2000 and 2018, I believe, the rate -- or I should say the revenue per customer collected by the utilities under price caps grew at a slower rate than the utilities under more traditional forms of regulation. So it does seem to be the case that there's some at least hint that maybe it does work. But, again, you can't control for everything. And as everyone in the room knows, there could be any number of reasons that that happened that are coincidental. And we did the best we could to control for the circumstances of the utilities, but we don't -- we -- I -- my paper, for example, didn't conclude that price caps were the reason. It was more like price caps are associated with slower rate escalation among customers. Now, other studies might be a little bit more definitive. And, Andi, I know you were just telling me the other day about the findings of the -- I think the Australian regulator that was reviewing their PBR mechanism, and maybe you could speak to what their finding was just briefly.

MR. ROMANOVS-MALOVRH: Sorry. Yeah, so the Australian energy regulator also has -- they have five-year multi-year rate plans. In this case, they're forecasted as opposed to having an indexed cap. They still adjust for inflation, and they have some other mechanisms in place as well. And in 2023 they conducted a review of their incentive mechanisms which included more than just the five year multi-year rate plan. But their conclusion was that the customers were better off, that the prices were lower. And they also had the service quality indicators in place which, in their case, were symmetric, like, had a reward component to it as well as a penalty component. And their conclusion was that the customers are better off. They acknowledged that there were areas of improvement which was part of what they did in that proceeding. But their over-arching conclusion was that it's successful, and they continued operating under that approach.

There was also a relatively recent study in Germany where -- so the utilities in Germany operate under revenue caps, but they have -- or I should say they operate under PBR, but they're they have a distinction between whether or not it's more -- whether or not the utilities have more incentives or less incentives depending on -- they basically have smaller utilities that are able to choose, like, an alternative regulatory approach. And, once again, the paper found that -- accounting for, you know, the various different -- differences between those groups, they found that the more restrictive or the model that you would think, in theory, has stronger incentives, also led to lower rates overall. But, once again, it's more of a -- it might have been more of an association rather than conclusive evidence that, you know, the more restrictive or more incentive-based approach actually led -- or was the cause for the reduction in rates.

MR. CROWLEY: I think it's also helpful to -- and I think it's helpful to think about who is authoring the reports sometimes because the -- for example, in Great Britain they operated under what they called RPI minus X which is essentially a price cap for many years until they transitioned to their REO (phonetic) approach. And at the end of the RPI minus X which was ended, I think, sometime in the 2014 or thereabouts era, Ofgem, the regulator, published papers proclaiming how successful -- like, it was amazingly successful. RPI minus X saved customers hundreds of millions of pounds per year. And maybe that's true and, you know, they present their argument, but also they are the ones who created the mechanism. So they have sort of an incentive to say that it worked out.

Anyway, so I tend to think that these mechanisms can be better than the sort of traditional way of regulation if designed well. It's sort of like the devil's in the details, but I also am clear eyed about the limitations and the need for certain additional tools to make sure that risk is controlled.

MR. SIMMONS: So, Nick, earlier you were talking about kind of the design of PIMs and an efficient PIM would give the utility the right signals as to whether to kind of try to attempt to meet the target or, you know, they could make the decision to take the economic hit of the penalties. And I guess I was wondering, you know, what your thought process is on that. If the targets that are set are kind of predicated on a certain level of capital investment, how would you -- you know, how should we think about that?

MR. CROWLEY: I think I need to talk through the question a little bit more to fully understand. So it sounds like you're saying how do we handle that there's capital that's required to provide the outcomes that we're looking for. Is the kind of meat of that question that it's like something that might not be -- or the investment sort of doesn't provide immediate outcomes. Is that where you're getting at?

MR. SIMMONS: So, no, I guess what I'm trying to ask is that so if the targets in a PIM are, you know, based on a certain level of investment so, you know, if it's -- you know, certain investments are made, we expect the target to be X. And, you know, the economic theory is that the utility has a decision to make as to whether, you know, they want to meet that target or pay the penalties.

MR. CROWLEY: Yeah.

MR. SIMMONS: How -- you know, if the investments are already included in -- you know, in the approved order, how do we kind of look at that going forward?

MS. HEALY: Ensure the utility actually spends the money in the way that the regulator intended the utility to spend it versus absorb the penalty. Is that right, Michael?

MR. CROWLEY: Well, now I --

MR. SIMMONS: That's a -- no, yeah.

MS. HEALY: Go ahead, Nick.

MR. CROWLEY: I'm sort of thinking about those two comments as being separate. So the first one, now, is, okay, there's embedded -- so the utility has made investments and then had a rate application where its rates have reflected investments that will then reflect -- the investments will then have an impact on the outcome of, like, the PIM essentially. So the rates already reflect costs that have been incurred in order to meet the PIM. Is that what you're saying?

MR. SIMMONS: Or if it's a future year, then --

MR. CROWLEY: Yeah. Yeah, I mean, that's a good point. And so, I mean, going back to the kind of -- I don't know if we had a -- I don't know if I put it in the slides, but at some point in here I had -- well, it probably was in this slide that I talked about it which is, like, how do you decide whether it's a reward-only or a penalty-only PIM. If my colleague Dan McLeod was here, he would say if the rates already reflect costs that have been incurred in order to meet the particular metric, then it should more likely be penalty only because the company's already collecting the -- it's collecting through rates the cost incurred to meet that goal. Now, I don't know that that's a hard and fast rule, though, because it might be the case that the company has incurred costs with the full intention of meeting the metric, and then the -- you know, it depends on -- I think it goes back to the question of are -- how in control is the outcome to the utility. So if the utility has made an -- like, let's think of a very specific example. Like, we have a -- we need to replace some poles or something to make reliability -- to improve reliability or do some -- I'm trying to think of capital investments that improve resiliency or reliability. And if the company makes those investments but then doesn't meet the reliability threshold and then has to pay a penalty, that doesn't quite seem like it's in the spirit of what we're trying to do because it's saying we're punishing the utility even though they did what they were supposed to. Something outside of their control happened and they didn't meet the PIM. So it's all kind of interconnected with the question of what's -- what is in the control of the utility. But I think it's important to consider also what's reflected already in rates. So if rates are collecting the cost of investments that are made to meet a certain threshold for a PIM, then I think we need to consider that maybe there's more likely that that's a penalty-only situation.

MR. SIMMONS: Yeah, so, Nick, that brought me kind of to my follow-up question. So if the example is, you know, they made the investments, but they didn't necessarily -- you know, they weren't on track to meet the target, would -- you know, would a symmetrical approach in that case give them the proper incentive to, you know, do more O&M or do some other actions that aren't necessarily related to the capital investments that they made?

MR. CROWLEY: Yeah, I mean, that -- I think that's possible. I think it -- it's sometimes a little bit hard to speak about these things so generally without knowing exactly what we're looking at. Having specific examples is helpful because we can assess a little bit more closely and in more detail, but I think that's an -- that's probably a good idea. I would also say just -- this is kind of a side note, but it occurred to me while we were talking about this, that -- so they have -- Duke Energy Carolinas in North Carolina has PIMs, and I was speaking with one of the regulatory folks at that company about their PIMs and how they went about designing them. And one of his comments was because there's so much that's outside of the control of the utility, I think one approach to designing PIMs is to -- specifically tying PIMs to the outcome of programs. Like, you have a program that says we will -- I mean, this is just an example, and I don't even know that this is something that they have in North Carolina. But, for example, we want to connect X number of DER customers this year, and either you do or you don't. And that's kind of, like, the threshold of whether you get the PIM reward. And so having something that's more, like, tied -- that's more -- I guess a little bit less easily defined like reliability where you have a SAIDI measure that has all these different potential impacts that are outside of the control of the utility, that makes it a lot more difficult to determine what is appropriate in terms of a reward or penalty. I'm not saying that it's not possible. Certainly, it's one of the most common PIMs that's out there, but I just think it makes it more tricky.

MR. SIMMONS: Thanks, Nick.

MR. DAVIDSON: So I have a question. This is Derek, and this is actually, I think, pointed more towards the stakeholders. So how do folks view symmetrical or reward-only PIMs? And do you think that they're appropriate? If they are, in what situations? Or are they appropriate in Maine at all?

MS. CHAMBERLIN: This is Susan of the Office of Public Advocate. I think a lot depends on whether or not it's within the normal expectation of what a utility is to provide. I don't think they should get additional incentives to provide, you know, safe, reliable utility services because that's what they're supposed to be doing. If it's something that's somewhat new or somewhat -- the path to doing it is a little uncertain, like, perhaps providing accurate and timely data for NWA, something like that, something they haven't had to do in the past, maybe there is a way to create an incentive to get them to focus on it. You know, something like that. But if it's squarely within the realm of their responsibilities, it makes more sense to me to say, look, you face a penalty if you don't do this because this is exactly what you're supposed to be doing. And I think the SQIs are along those lines. It's like, okay, this is within your realm. This is what we expect. If you're not meeting it, what's going on? I think it raises a flag.

MR. GRUMSTRUP: Susan, would you include interconnections in that category or would you see that as something utilities are already expected to --

MS. CHAMBERLIN: Well, that one -- it is in the -- kind of changing their role. It's a somewhat new thing that they're supposed to be doing. It is within their realm, but there are a lot of variables as has pointed out (sic). There's only so much within their control. So I think if it were to be the subject of a penalty, it should be very narrow, narrowly tailored. What is it they can actually do to promote it? If it sits in the ISO for a year and a half, I'm not sure that there's a lot they can do. Maybe there's some things they can do to help that.

MR. BURNES: I wonder whether -- when it comes to rewards, whether there's a way of looking at it is -- you know, as a way of -- because I very much agree with Susan. But I also feel like especially with the grid plan, we're asking the utilities to sort of be innovative, perhaps -- let's use interconnection as an example of perhaps proposing and implementing a flexible interconnection approach that would -- something along those lines that we set some goals. And the Commission might even say for something that is more innovative than their basic bread and butter utility service, that we would be open to rewards if you would take a leadership position in these kind of things. Because I think that absent a specific plan for -- from the utility to innovate, it very much could start to look like we're paying them to do exactly what they're doing. And I think that's going to be a non-starter. But to tie it to innovative behavior could help us to incent. And they know their systems better than anybody. They know how -- what that's going to look like. Because I'm also a little uncomfortable, like, you know, even leaving beneficial electrification as a potential goal. And we recognize that, you know, rate design, there are some things that could -- that fit within their purview that they could do, but I really don't want the utilities sitting there thinking about, oh, how do we get into the beneficial electrification game. Like, how do we push into that zone? Like, that's not the right policy signal for us to be thinking about. So I think we just need to be really, really careful about distorting behavior with rewards.

MS. HEALY: What about something like, you know, the utilities' conversion of customer bills to electronic billing and electronic communications? Would you view that as something that's sort of in the core, you know, bailiwick, as something that the utilities should already be doing, or would you view that as something that's more innovative? I mean, I think there are cost aspects -- you know, cost savings aspects to something like that. There are also, you know -- and I wouldn't attempt to quantify these, but things like greenhouse gas emissions benefits, you know, because you're not putting paper in the mail that's getting trucked all over the place and those types of things. Just -- I'm just throwing that out as an example to sort of test what --

MR. BURNES: I actually really don't know where they stand on that. So I -- but --

MS. HEALY: No, I'm just asking you. Like, would you consider that -- would you -- would that sound more to you like something that would be --

MR. BURNES: Yes. I mean, like, I actually -- that specific example, I'm -- I -- as a CMP customer, I think I'm already doing that. But I think that the -- I actually think there's a lot of innovation that could fit under the category of how we meter, bill, and settle energy. And coming up with new approaches on how that could overlap with beneficial electrification and interconnection of DERs could be -- that -- I would absolutely --

MS. HEALY: That would be more -- would you consider that more of a reward type situation?

MR. BURNES: Yeah.

MS. HEALY: Okay.

MR. BURNES: Yeah. You know, like, if you came up with a way of increasing the implementation time of some of the -- yeah, I think that that's a perfectly -- a perfect place to say, yeah, we would give you a higher ROI on these investments if it met these kind of criteria. Yeah, absolutely.

MS. HEALY: Do other stakeholders have thoughts on that?

MR. COHEN: I do.

MS. HEALY: Go ahead, Peter. You're a stakeholder.

MR. COHEN: So I'll give you one -- a CMP employee's opinion, not necessarily representative of the entire company. I'm not speaking for Versant. Financial incentives, but you're talking about aren't really that interesting in terms of it helping me, you know, increase my earnings because it's just they're never going to be that big and that's not really what motivates me. And I also think I can speak on behalf of CMP. Incentives motivate me more of out of fairness. So, for example, if there is a reliability metric that can be influenced by car crashes on the highway, like reliability, I have no ability to control how people are driving. But yet, if people are driving a little bit more crazy this year relative to the benchmark year, I can have a financial consequence that's completely outside my control. And I've accepted that, and Chapter 320 has enforced that. There is a negative incentive only PIM or however you want to refer to it. And that seems unfair to me because what about the year where there's less car crashes and I didn't do anything about that either? I don't get a benefit there. I just have the negative consequence. And so what I like -- and I -- I'll correct the Christensen -- we actually do have a PIM that is not just negative at CMP. We can offset negative performances for our service quality metrics with positive performances. And so, for example, if we fail to meet SAIFI, we can make it up with CAIDI. And if we fail to meet ASA 30, we can make it up in, you know, percent of meters read. That came in our last rate case, and I think people thought, oh, well, you know, who cares, they'll never use it. And we never used it. We never needed it. We met all our metrics, you know, that were harder than Chapter 320 and progressively harder through the years. But it meant a lot to the utility to know that there was a way of offsetting the uncontrollable so that it wasn't always hurting me as a company. And so I don't -- what a utility wants is a framework. We don't want a one-year plan where we have to keep coming in over and over again. I don't mind reporting. I don't mind being held accountable. I don't mind having negative revenue adjustments. I just want it to be fair, and it's not always, well, let's assume that the utility is a bad actor, let's assume that they're only motivated by sheer profit alone. Because I can tell you that we have a thousand employees at CMP that don't think of it like that. We don't look at our balance sheet and our income statements every day. We look at our customer service metrics every day, I can tell you that. We have a weekly report from Linda Ball that talks about our -- you know, how we're doing and how we're doing against plan. When -- anyways, so I just don't want folks to get the idea that if you offer me some 25 basis point incentive to do something, that that's really that interesting. But if you let me have a multi-year rate plan where we can focus on the things that will help you achieve those objectives, that's really what a utility wants. And that's what performance-based ratemaking -- we already have that. I mean, CMP already has that. And I feel as though we've done well over the past couple of years. We met all our metrics. You know, things seem to be good. We're not over earning by any stretch of the imagination. But we're not crying either about it. We're just doing our best, and I guess that's my feedback for the consultant as you think about it. We already have performance-based ratemaking as you've accurately diagnosed, a lot more than people think. And we have earnings sharing mechanism that only goes one way, for example. So it protects customers. We have downward-only reconciliation of capital spending. Only goes one way, protects the customer. We have a lot of customer protections that this utility itself proposed in its last rate case. It wasn't enforced on CMP. We proposed it when we asked for a three-year multi-year -- three-year plan. And that's kind of how at least CMP views this, and we're happy that this is occurring, this inquiry, so that we can be an active participant. But don't think, you know, you give me a ten-basis point thing if I do this right or that right. I was going to do that right either way. Just make it fair, that's all.

MR. CROWLEY: So if I might just say two things in response. First, just want to confirm the -- what you had said regarding the SQIs being not only penalty related. We -- at the top of page, I think, 72 or 71 of our report, we do talk about that. It's 72, that Central Maine Power can offset penalties within the same category for improvements in performance. Or they can use improved performance to offset poor performance. Is that the characterization that you would put it?

MR. COHEN: Yeah.

MR. CROWLEY: Okay, I agree. I still think it's penalty only because you never get a reward for that.

MR. COHEN: That's not a -- that's not how a utility looks at it, just so that you know. In fact, we were very excited to have the ability to offset with a positive.

MR. CROWLEY: Okay.

MR. COHEN: So, yeah, as far as the utility is concerned, that is a positive benefit.

MR. CROWLEY: Okay.

MS. TUGGEY: This utility anyway.

MR. COHEN: Yeah.

MR. CROWLEY: All right, well, that's helpful. The second thing I wanted to say is just to echo -- sorry, I don't your name in front of me, the person who was just talking. Peter? Peter Cohen? Yeah, so another point that you just made about the PIMs -- you know, the -- you know, you give a few basis points here and there on ROE and that doesn't affect behavior that much. I will just say from my experience speaking with the director of regulatory at Hawaiian Electric Company on this exact point, he had the same thing to say. He -- his -- so in Hawaii, how PBR went about happening in Hawaii is that they had this kind of long prolonged stakeholder engagement. They had all this collaboration, many, many years of work that went into the Hawaiian Public Utility Commission ultimately saying, okay, Hawaiian Electric Company, you now have this revenue cap and also you have these six PIMs. And I think what -- I don't know that there's any, like, documentation that I have that I can give you on this, but what they felt is that the PIMs were kind of aspirational and they ultimately didn't do that much to change any kind of behavior because of the reason that Peter was just saying which is that, you know, in the case where -- there are some cases where there are things that -- you know, there were policy goals that were being reached for, but the reward just simply wasn't sufficient to incent the behavior toward getting to those policy goals. And then in other cases, the utility already was going to do the things that it was going to do anyway under those PIMs. And so it -- the -- what would be interesting is to learn if there's -- I'm not aware of any academic research that has been done to say that PIMs do a whole lot to change utility behavior. Now, the theory would say that it would because if there's ever money on the line, the utility should be trying to minimize the loss and maximize the benefit. But sometimes there are practical limitations to that. So I'll just say that I've heard that in other jurisdictions.

MS. HEALY: (Indiscernible) about 20 minutes left. Does anyone want to respond to that topic or bring anything else up?

MR. MARSHALL: I had kind of a new question if I could.

MS. HEALY: Yeah, go ahead. Brian from the Public Advocate's office.

MR. MARSHALL: Yeah, Brian Marshall for the OPA. So in the PBR framework, the I minus X, you know, that makes sense to me as providing this strong cost control mechanism on a utility, but in a lot of the examples you pulled from, there's, you know, all these other things layered in. And especially when we start talking about things like capital trackers, it strikes me that you could really be distorting the cost control incentives there, right? So if I'm thinking, like, for any given solution or most solutions, there's, you know, conceivably an O&M solution and a capital solution. And what we want to do is encourage the utility to find the best mix of O&M and capital. But if you're only giving, like, separate specific recovery for capital spend, then aren't you really sending the incentive to the utility that they should be spending more capital? You know, just to give you some specific examples, you know, you could trim the trees more or install, you know, some capital -- covered conductor or replace the poles. Both of those solutions go at reliability. One does it through O&M, one does it through capital. So if you're allowing the utility to recover separately just those capital investments, haven't we distorted this whole analysis? Maybe you could help me out with that part of it.

MR. CROWLEY: I think the answer to that is yes. There's -- the most pure form of PBR would be just I minus X. But what we encounter in the world of distribution utilities, especially lately, is that I minus X -- so I minus X, if perfectly calibrated, would give the utility what it needs in order to survive a five-year rate stay out period. But the X factor, generally speaking, is based on historical TFP, and that historical total factor productivity is potentially reflecting conditions that are not the conditions the utility's going to experience in the next five years. So, like, in the -- so, for example, if a utility had come in for a price cap filing in the year 2020 and it had an X factor based on total factor productivity growth from the year 2005 to the year 2019, that X factor would not be giving that utility enough revenue support most likely to meet its capital needs for the next five years because, as we know, everything became incredibly expensive and in a way that wasn't necessarily reflected in the inflation measure right away. So to sort of come back to the question is it distorting utility incentives, I think the answer is yes, but also there's a practical question of, you know, what is the -- what is it -- what is the utility actually able to do? And if I minus X is insufficient, which it has been in recent years, then there needs to be some form of capital supplement.

I'll also say a lot of regulators lately have been accepting zero percent X factors which are not based on total factor productivity but are arbitrarily chosen. And if the X factor was empirically set, the need for a capital investment support would go down because the X factor is -- the empirical X factor is negative these days.

MR. COHEN: Isn't the K factor actually meant -- so the way that this formula would work is that everything is pegged on some sort of inflation less an X factor if it exists or a Z factor if it exists. And so the K is meant to suggest that there may be times like right now when capital investment needs outpace the inflation that would be supporting it in a price cap. Do you see what I'm saying? So it's not necessarily -- I think, Brian, you might be thinking it's like a targeted program. If you can, you know, focus on tin cans, then you can have this as a tracker. I actually think that a price cap, that K, is more about this differential between the underlying inflation assumption and the needs of capital investment, you know, at a macro level. Or am I thinking about that wrong?

MR. CROWLEY: It's close, but one thing that I'll say is that, like I said earlier, if the X factor could be completely accurately calculated, then that concern would go away because what the X factor is doing is saying -- the X factor is not a -- is not an optional component to the price cap. It is -- the I minus X formula is derived from economic theory where the I factor is input prices. So the price that the utility is paying for the stuff that it's buying, that includes capital and labor, like, the wage cost and the cost to buy a transformer, for example. But the X factor is how much of that stuff do we need to buy and how much output are we producing with what we buy. The X factor is productivity. So it's like the percentage change in output minus the percentage change in input. If you're needing more -- if the industry needs more and more input in order to produce the same amount of output, that X factor will be negative. And that means that the annual adjustment to rates is going to be higher than the rate of inflation which I know I'm saying that stuff kind of fast, but --

MR. COHEN: No, it's fine. It's just not the same amount of output. So I hear what you're saying, though, and I understand.

MR. CROWLEY: But -- yeah, so that's -- in summary, if you had an X factor that could be accurately reflective of what the utility's going to be experiencing over the next five years, most likely the K factor would be less important. But it's -- we really don't live in a world where that is the norm lately, is that X factors tend not to be set according to TFP and instead are sort of set arbitrarily by the regulator which is something that I would advocate against. I think if you're going to have an X factor, it should be based on the data.

One other thing on K factors that I'll mention is that they're not all the same. I think I have -- yeah, this slide here just shows an example of different types of capital funding mechanisms. And if you focus on the last one, K-bar, K-bar is one that is probably, out of these, the most -- it provides the utility with the best cost efficiency incentives with regard to capital because under the first three, it's basically some form of cost-based revenue recovery mechanism where the utility says I incurred or plan to incur these capital costs, can I please collect the revenue that I need to make those costs. K-bar says there is sort of a mechanized revenue requirement that we expect to need based on our past spending, recent past, usually, like, last three years, maybe last five years, and if I minus X doesn't give us that, then we need the rest of it. And so the utility under that kind of approach does have more incentive to reduce its capital spending than maybe under a capital tracker approach.

I had another point on this which is that I -- getting all the way back to the first point that was made, isn't it distorting incentives, and I said yes. But the thing about operating under a price cap or a revenue cap or a well-calibrated multi-year rate plan is that the utility has an incentive to reduce its costs. It's not really a concern that the utility's going to be spending more on capital under one of these approaches because the utility has an incentive to spend less generally speaking. Usually the concern is will the utility spend enough on capital. And so that's what the tracker or the kind of additional capital spending approach is trying to do is say, okay, we know that under pure I minus X with no capital supplements, the utility has an incentive to reduce its costs. But we have to make sure that the utility doesn't stop spending money on needed capital. So we're going to give this additional tool to make sure that there's not potentially damaging, like, cost reduction happening. Anyway, that's one of the theories behind capital funding.

MS. HEALY: Thank you. Anyone else on Teams have questions, comments? Okay, anyone else in the room have questions, comments? All right, well, thank you, everyone, for the discussion this morning. This was very interesting, and certainly please consider filing written comments, and we look forward to receiving those. And I think with that, we'll call it the close of the workshop, and I hope you all have a good weekend. Or a good afternoon if you're coming back here this afternoon.

MR. SIMMONS: Thanks to the Christensen folks for joining.

MS. HEALY: Yes, and thank you very much, Nick and crew. We really appreciate it. And we'll be in touch.

MR. CROWLEY: Yeah, thanks to everyone, and I look forward to seeing --

MS. HEALY: And I'll wait to receive the updated slides from you, Nick, and people can probably look for the slides on Monday.

MR. CROWLEY: All right. Well, I'll send them along this afternoon. Thank you, everyone.

CONFERENCE ADJOURNED (May 16, 2025, 11:51 a.m.)

C E R T I F I C A T E

I hereby certify that this is a true and accurate transcript of the proceedings which have been electronically recorded in this matter on the aforementioned hearing date.

D. Noelle Forrest

D. Noelle Forrest, Transcriber

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2025-00107

May 22, 2025

PUBLIC UTILITIES COMMISSION
Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

PROCEDURAL ORDER
(Christensen's Presentation)

The Commission appreciates the thoughtful participation of those that attended the May 16, 2025 workshop. Christensen Associates Energy Consulting's slides from its workshop presentation are attached as Attachment A. Further, the Ontario Energy Board resource that Christensen posted to the meeting chat may be found at: OEB Releases Discussion Paper on Performance Incentive Mechanisms | Advancing Performance-based Rate Regulation | Engage with Us.

As described in the April 30, 2025 Notice of Inquiry written comments regarding Christensen's draft report may be filed by **Friday, May 30, 2025**. Written comments should be filed in the Commission's Case Management System under the "filings" module. For instructions how to file with the Commission, please visit https://www.maine.gov/mpuc/online-services/electronic-case-filing-consumer-complaint-system-documentation.

Dated at Hallowell, Maine, this 22nd day of May 2025.

BY ORDER OF THE PRESIDING OFFICER

Nora Healy

Nora Healy

Presiding Officer

Attachment A

Performance-Based Regulation in the State of Maine

May 16, 2025

Nick Crowley, Xueting (Sherry) Wang,
Andi Romanovs-Malovrh,
and Corey Goodrich

Christensen Associates Energy Consulting

A wholly-owned subsidiary of Laurits R. Christensen Associates

- Costing, pricing, econometric analysis, and alternative regulation research across many industries:
  - Electric and gas utilities
  - Telecommunications
  - US Postal Service
  - Railroads
  - Oil Pipelines
- Empirical work and qualitative research:
  - Total factor productivity
  - Cost benchmarking
  - Performance incentive mechanisms
  - Regulatory framework design
- Work products include reports, testimony, presentations, and regulatory strategy

Recent PBR Work

EPCOR

New Hampshire Department of Energy

nationalgrid

ONTARIO ENERGY BOARD

EVERSOURCE ENERGY

BC Hydro

Unitil

Indiana Utility Regulatory Commission IURC

Workshop Outline

1. Project Background and the Purpose of this Meeting
2. Defining Performance-Based Regulation (“PBR”)
   - Performance Incentive Mechanisms
   - Multi-Year Rate Plans
3. Maine’s Existing PBR Tools and Policy Goals
4. PBR Tools for Consideration in Maine
5. Observations and Next Steps

Attachment A

Project Background and the Purpose of the Meeting

Christensen ASSOCIATES

Project Background

- **Purpose:** Evaluate PBR tools that may be used to regulate investor-owned electric utilities (IOUs) in the state of Maine
- **Scope:**
  - Review of the standards and metrics utilized in other states that have implemented PBR
  - Assist the commission in developing goals for utility performance and translate these goals into performance-based standards and metrics
  - Identify emerging regulatory mechanisms that would better align utility performance with state policies and goals when compared to other traditional forms of regulation

Stakeholder Engagement Meeting Purpose

The purpose of this meeting is to:

Present our findings on relevant PBR tools and how they may be applicable for Maine

Listen to your feedback on policy goals and the application of these regulatory tools to Maine.

Attachment A

Defining "Performance-Based Regulation"

Christensen ASSOCIATES

Forms of Utility Regulation

Traditional Regulation: sets rates with cost-of-service filings as frequently as required by the utility

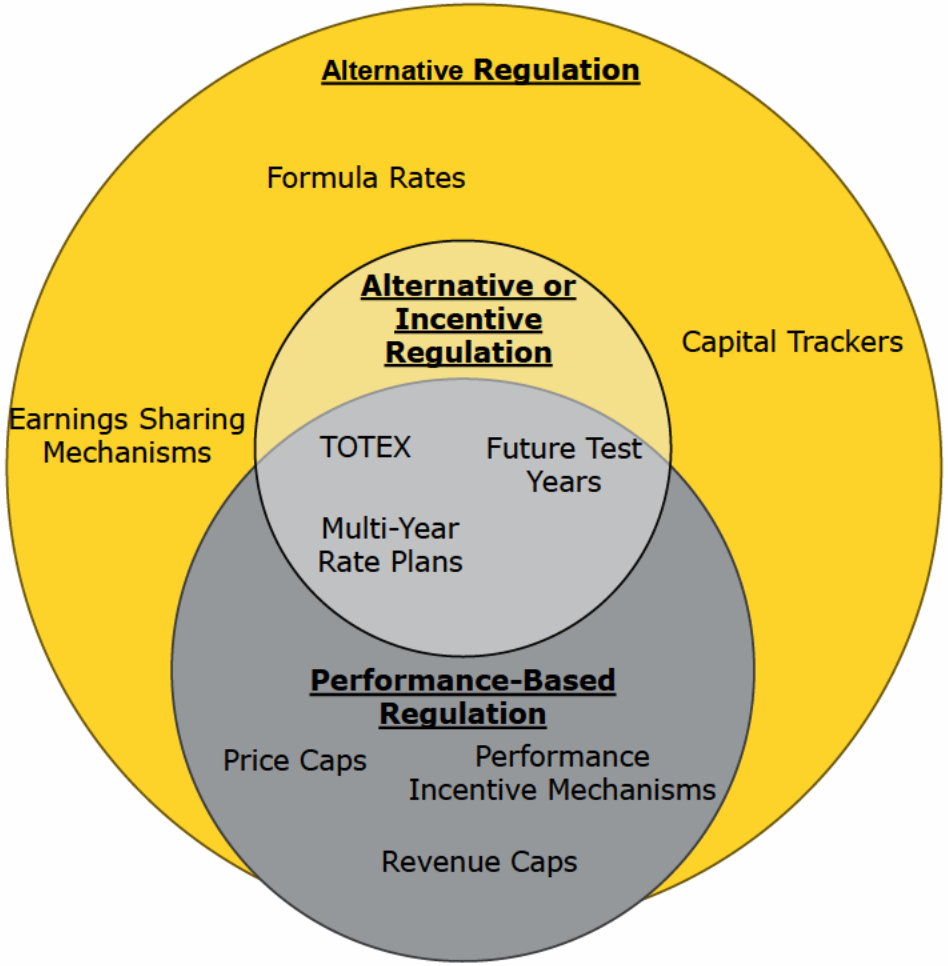
Alternative Regulation: can mean any deviation from traditional regulation.

- Does not necessarily mean improved incentive properties.

Not Synonyms!

Performance-Based Regulation: is generally considered a subset of Alternative Regulation

- By definition, focuses on incentives
- Also known as Incentive Regulation



Christensen ASSOCIATES

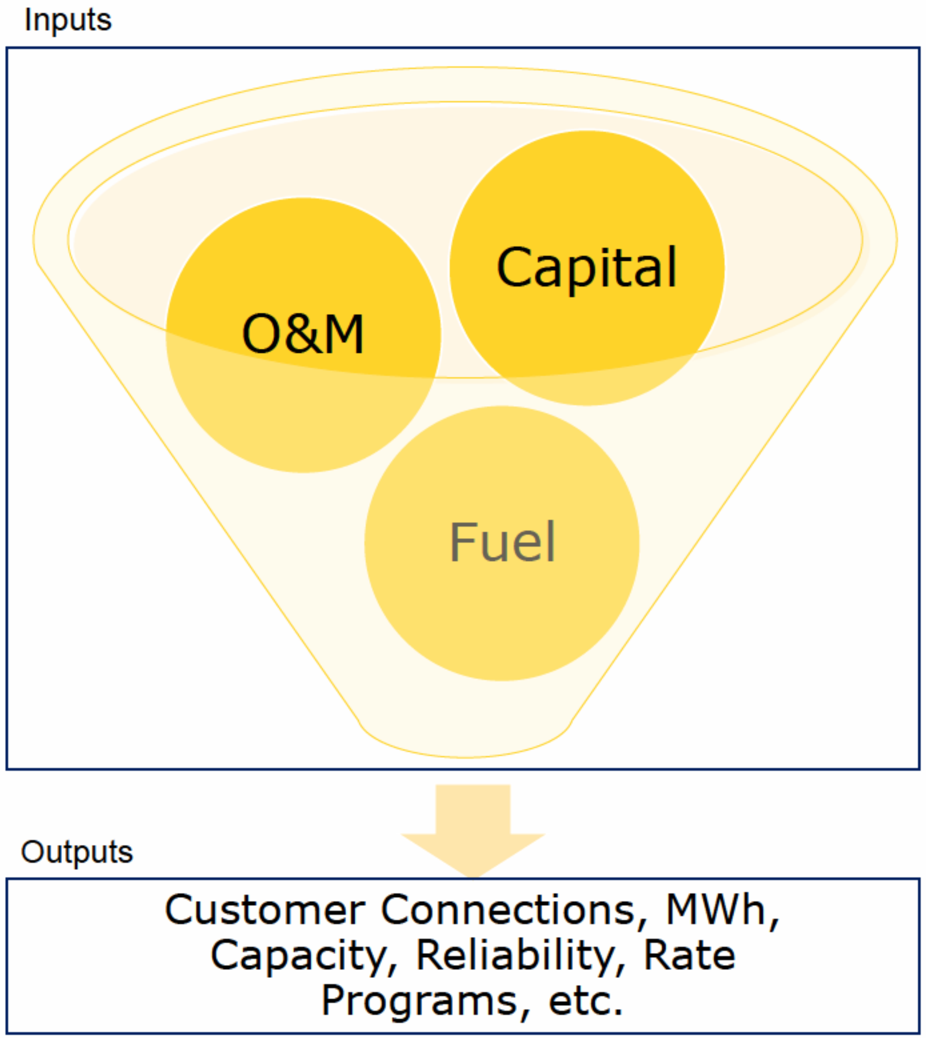
PBR – Fundamental Tools

1. MYRPs (Forecasted or Indexed Capped)

- Incent the utility to produce outputs using the least-costly combination of inputs.
- Key Question: What framework provides incentives, but is also feasible?

2. Performance Incentive Mechanisms

- Provide financial incentives for the utility to provide certain measurable outputs.
- Key Question: What are, or should be, the utility's outputs?



Traditional vs. Performance-Based Regulation

Note: Terminology is tricky!

TRADITIONAL

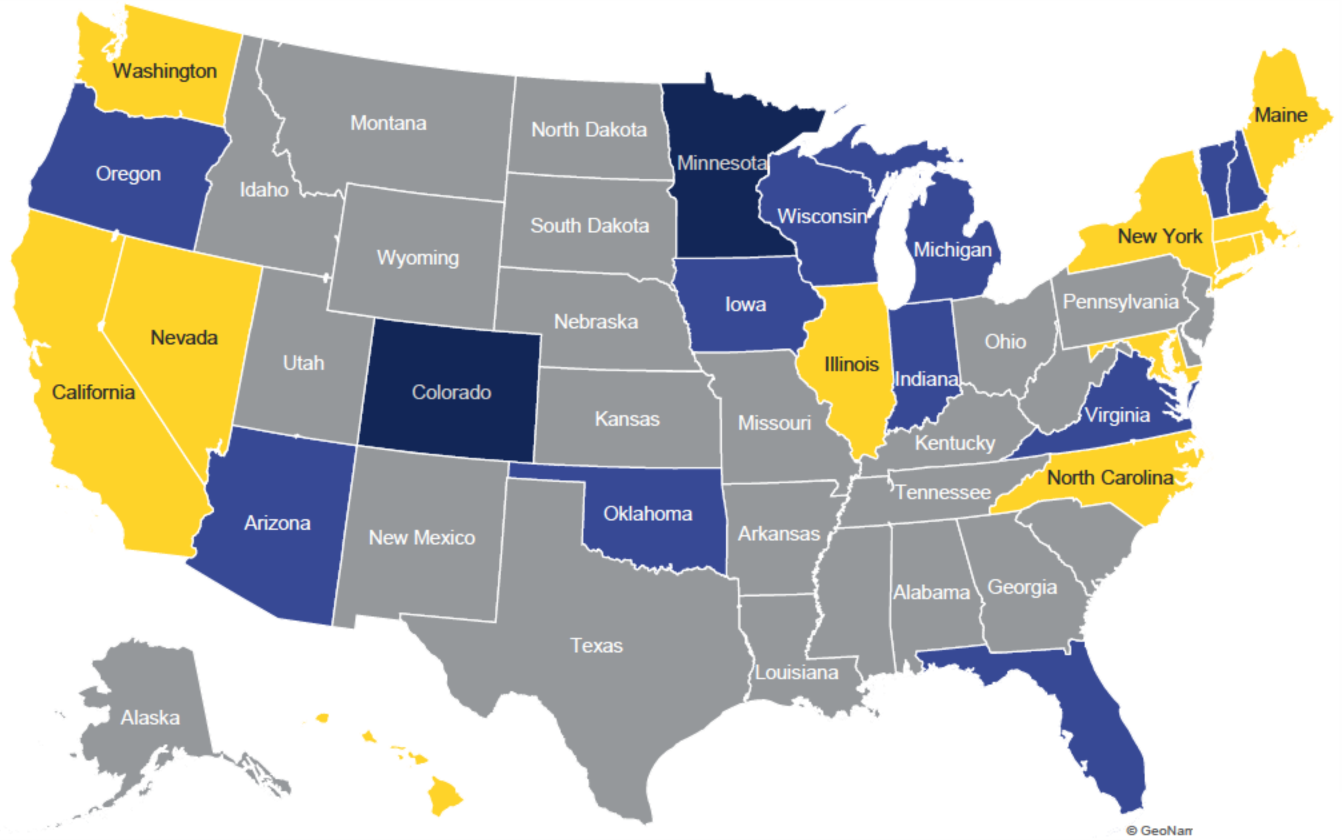
- **Cost-based:**
  - Costs and revenues are closely linked
  - Allowed rate of return set by the regulator
- **Frequent rate applications when costs are rising and outputs falling:**
  - Rate applications could be as often as every 1-3 years
- **Relatively low incentives:**
  - Efficiency gains quickly returned to consumers; poor efficiency recovered
  - Desired outputs may not be delivered

PERFORMANCE-BASED

- **Revenues and costs could be disconnected**
  - Utility may earn above or below the cost to serve over an extended time
  - Rate of return may be more dependent upon performance
- **Less frequent rate applications:**
  - Rate stay-out periods extend the time between cost-based rate adjustments
- **Designed with enhanced incentives:**
  - May mimic competitive markets
  - Incent production of certain outputs

Attachment A

Status of PBR Across United States



- No PBR
- Exploration
- Implementation
- Implementation On Hold

Connecticut
Delaware
Hawaii
Maryland
Massachusetts
New Hampshire
New Jersey
Rhode Island
Vermont
Washington D.C.
West Virginia

Attachment A

Existing PBR Tools and Policy Goals in Maine

Christensen ASSOCIATES

Existing PBR tools in Maine

1 Multi-Year Rate Plans

Distribution utilities in Maine are allowed to propose plans that:

- cover multiple years
- pair with forecasted or indexed rate increases

2 Service Quality Indicators (SQIs)

- Reliability indices
- Customer service response time
- Billing accuracy

Proposed Policy Goals in Maine

1	Promote efficient and cost-effective transmission and distribution utility operations
2	Increase planning and preparation for extreme weather events and climate hazards
3	Promote cost-effective and comprehensive responses to outages
4	Increase affordability and customer empowerment and satisfaction
5	Support achievement of the State's goals for increasing consumption of electricity from renewable resources
6	Advance the State's greenhouse gas emissions reduction goals
7	Advance beneficial electrification

Attachment A

PBR Tools for Consideration in Maine

Christensen ASSOCIATES

Indexed Caps: Price and Revenue Caps

Price and Revenue caps emulate competitive markets

1. Revenue requirement set in initial rate application
2. Formula fixes company's price or revenue growth at the rate it would face in a competitive market.
3. Company will cut costs to maximize profit if it retains some profit for doing so.
4. Rates reset according to cost-to-serve in next rate application (typically 5 years later)

Typical Price Cap Formula:

$$\% \, \Delta \text{Price} = I - (X+S) + Y + Z + K$$

The core "I – X" formula:

- I: input price inflation
- X: industry productivity

Adjustments:

- S: stretch factor
- Y + Z: exogenous factors
- K: supports capital investment

Can Indexed Caps be Applied in Maine?

Advantages

- Indexed caps aim to provide cost efficiency incentives
- Maine's IOUs are "lines-only" utilities, which is similar to other jurisdictions where utilities operate under indexed caps
- Past experience with price caps in Maine

Challenges

- Maine's IOUs are transmission owners:
  - Larger and lumpier investments
  - Transmission projects are often directed by ISO-NE
- If adopted, indexed cap PBR should be accompanied by factors that allow for the recovery of costs beyond utility management's control

Making Indexed Caps Feasible

- Price cap formula forms the basis of the PBR plan
- Additional elements are often included :
  - Exogenous factors
  - Capital trackers
  - Additional guardrails
    - Earnings sharing mechanisms
    - Reopeners/Off-ramps

Fuel cost trackers
Tax changes
Storm cost recovery
Pension costs
Insurance costs
Transmission charges

E.g.,
Hawaii: Exceptional Project Recovery Mechanism;
Ontario: Incremental Capital Module
Massachusetts and Alberta: K-bar

Can PIMs be Expanded in Maine?
Utilities in Maine already operate under penalty-only PIMs

- PIMs can be reward-only; penalty-only; or symmetrical
  - Maines SQIs for basic service quality are penalty-only
  - Both New York and Hawaii have reward-only and symmetrical PIMs
- Other jurisdictions have introduced PIMs to encourage investment or action to meet policy objectives similar to Maine's policy goals
- Distributors in Maine have less control over certain outcomes such as greenhouse gas (GHG) emissions

Advantages and Challenges of PIMs

ADVANTAGES

Alignment with Public Policy Goals

- Targeted incentives allow regulators to promote important policy goals
- Can shift the focus from capital investment to measurable outcomes

Focused on efficient outcomes

- Utility provides service demanded by customers and is rewarded according to the value of that service

Flexibility and Transparency

- Increases transparency in utility performance through measurable metrics
- Incentive mechanisms can be changed to adjust to changing market conditions

CHALLENGES

Design Complexity

- Difficult to quantify performance outcomes and set appropriate rewards/penalties
- Limits to timely access to metrics

Accounting for External Factors

- Uncontrollable external factors may impact performance metrics
- Mechanism must balance fairness with administration simplicity

Unintended Consequences

- Poor design can lead to attention toward specific goals to the detriment of service that is not rewarded/penalized
- Risk of gaming or manipulation by utilities

Observations and Next Steps

- Maine IOUs face service quality indicators that meet the definition of PIMs
- The state's Alternative Regulation option currently allows the utilities to file a MYRP
- Other jurisdictions require electric utilities to operate under some form of PBR
- Christensen Associates will provide recommendations following this stakeholder engagement meeting

Questions for Stakeholders

- Are the proposed policy goals appropriate for guiding the design of a regulatory framework in Maine?
- Are there nuances to the current regulatory framework in Maine that are not fully reflected in the Christensen report?
- Is an expansion of PIMs in the state appropriate? If so, how should they be developed?
- For the utilities: what guidance do you need from the Commission before putting together a rate application with PBR tools that are not currently used in Maine?

Appendix: Additional Material

Christensen ASSOCIATES

Ontario – Electric Distribution Utilities

1. The Ontario Energy Board has operated under PBR since 2000
2. Electric utilities may select a choice from a menu of options
    - Price cap
    - "Customer IR"
    - Annual IR Index
3. Each utility has a different PBR plan
    - Some with ESMs, some not
    - X factors vary
    - Stretch factors vary
    - Capital supplements are utility-specific
4. Natural Gas (e.g., Enbridge Gas Distribution) also operate under PBR in Ontario

Alberta – Electric and Gas Distribution Companies

Electricity and gas distribution currently operating under third generation PBR framework

1. Single proceeding captures all utilities, every 5 years
2. Asymmetric ESM approved in 2023
   - 200 bps deadband
3. Supplemental capital mechanism included
4. Although positive stated X factor, effective X negative once capital funding considered
5. No service quality or other PIM adjustment factors

British Columbia - FortisBC (Electric and Gas)

1. Currently operating under a five-year MYRP
2. X factor + Stretch factor of 0.5%
3. Electric and gas PBR frameworks differ in treatment of capital
   - Electric: All capital is forecast
   - Gas: “Sustainment” capital is forecast
4. Earnings sharing with no deadband
5. Flow through (Y factor) treatment of costs for many deferral accounts
6. No service quality or other PIM adjustment factors

Hawaii – Integrated Electric Utilities
Docket 2018-0088

1. Revenue cap with an X factor of zero
2. Over 60 different performance metrics
3. Symmetrical ESM
4. Capital supplement: "Exceptional Project Recovery Mechanism"
5. Reopener with three possible triggers:
   - ROE threshold
   - Credit rating downgrade
   - Commission discretion

Massachusetts Eversource (Electric Distribution)
Docket DPU 22-22

1. Second Generation plan approved November 2022
   - First generation plan had first negative X factor in U.S. electric utility regulation
2. Asymmetrical ESM: profits shared; losses not recovered
3. No PIMs
4. Added a capital supplement akin to Alberta's in PBR2
5. In the first generation, extensive stakeholder education process prior to filing

Massachusetts - Eversource (Gas)
Docket DPU 19-120

1. Revenue cap with a negative X-factor
2. 10-year rate stay-out period
3. ESM above 100 basis points
4. Consumer dividend of 15 basis points
5. Z-factor for O&M expenditures over $700K
6. Set of scorecard metrics to measure the success of PBR Plan implementation

California – Multi-Year Rate Plans

1. Four-year MYRP
2. Uses mechanisms other than "incentive" mechanisms to achieve goals
   - Example: Demand response programs
   - No PIMs!
3. The utility remuneration framework includes capital cost trackers

Distribution Regulation	
Regulated Utilities	6
Ratemaking regulator	California Public Utilities Commission
Transmission Operator	California Independent Systems Operator
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	
Price Cap	
PIMs	
Earnings Sharing Mechanisms	

New York – REV

"Reforming the Energy Vison"

1. Three-year MYRP based on forecasted cost to serve
2. Have seven "earnings adjustment mechanisms" (essentially, PIMs)
   - Includes "Non-Wires Alternatives" incentives
   - Additionally, NY utilities have scorecard metrics (with no financial incentive)
3. Considered TOTEX, but did not adopt it

Distribution Regulation	
Regulated Utilities	6
Ratemaking regulator	NYPSC
Transmission Operator	NYISO
UR Elements	
Multi-Year Rate Plans	✓
Revenue Decoupling	✓
Revenue Cap	
Price Cap	
PIMs	✓
Earnings Sharing Mechanisms	✓

Incentive Regulation Beyond North America

- United Kingdom
  - RPI-X (early 1990s-2013)
  - RIIO-1 (2013-2021)
  - RIIO-2 (2021-2028)
- Australia
  - Revenue caps set with building block approach
  - Both distribution and transmission
- New Zealand
  - Revenue cap on distribution utilities

RIIO: Revenue = Incentives + Innovation + Outputs

- Separate (but similar) price controls exist for:
  - Electricity distribution
  - Electricity transmission
  - Gas distribution
- Five-Year MYRP approach using both forecasts and inflation to set revenues.
- The distributor base revenues (set in 2012-13 prices) are inflated in the Retail Prices Index (RPI).
  - Plus incentive rewards or penalties for over- or under- delivery of the outputs utility must deliver.
  - Uncertainty mechanisms

Capital Funding and Indexed PBR

- Capital funding needs have often outpaced output and revenue growth
  - Electrification
  - Replacement of ageing plant
- Different jurisdictions have addressed this problem in different ways

Approach	Jurisdictions	Methodology
Forecast Capital	British Columbia; Australia	In the PBR proceeding to set initial rates, the utility establishes a forecast of capital spending costs over the PBR term and recovers these costs through rates.
Cost-of-service (capital trackers)	Massachusetts	Gas utilities in Massachusetts may recover capital expenditures beyond the PBR formula under the state's Gas Safety Enhancement Program.
Project-Specific	Ontario; Hawaii	Utilities may recover costs for projects that meet certain criteria. Known as the Exceptional Project Recovery Mechanism in Hawaii, and the Incremental Capital Module in Ontario.
K-Bar	Massachusetts; Alberta	This approach provides a capital spending envelope based on the utility's own trend in historical capital spending.

- Price cap is now

$$\%\Delta \text{Price} = I - X + Y + Z + K$$

Capital Supplements – K-Bar

Key Features:
- Uses company-specific historical spending to set future revenue growth
- May be designed with a static time period or a rolling average

Advantages:
- Retains cost containment incentives of an effective PBR plan
- Has no forecast inflation risk

Disadvantages:
- More difficult to understand
- Obscures the meaning of the X and Stretch factors
- Hinges on the assumption that investment decisions in the past are an accurate predictor for investment decisions in the present

K-Bar Calculation Steps:

Step 1: Calculate the "going in" capital-related revenue requirement that is recovered in the base rates under the I-X mechanism for the first year of the PBR term. This is the sum of the Company's depreciation expense, the return on rate base, and property taxes.

Step 2: Establish the percentage change in revenue collected under the I-X formula, which in this case is set equal to GDP-PI minus zero.

Step 3: Determine the capital recovery supported by I-X for a given year by inflating the "going in" capital revenue requirement by GDP-PI.

Step 4: Calculate the notional revenue requirement for capital expenditures the year, based on historical capital spending.

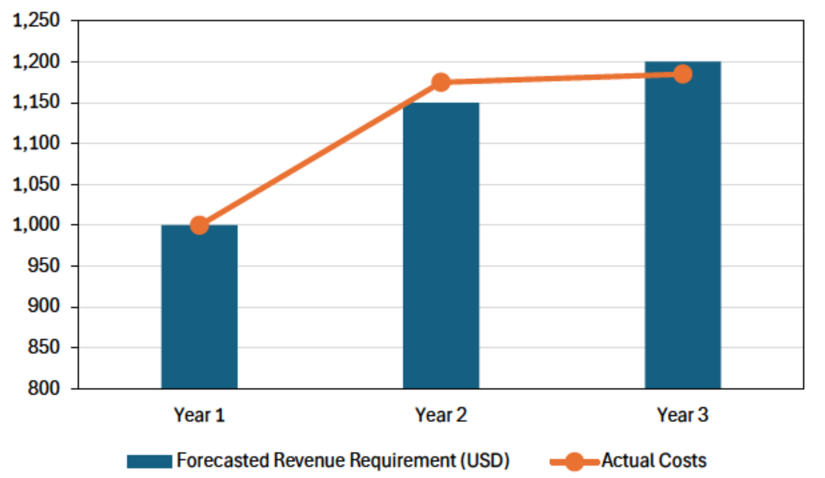
i. Obtain capital additions for each of the past three years.
ii. Inflate each of the capital additions to current dollars using the approved I-X formula, with the approved I factor for each year and the approved X factor for the prior generation PBR plan.
iii. Using the inflated capital additions, calculate the average K-bar capital additions over the historical three-year period.
iv. Inflate the average K-bar capital additions to the current year using the new approved I-X formula.
v. Calculate the amount of K-bar capital cost incurred for the current year as the sum of depreciation, return on rate base, and property taxes, based on the current year capital additions from the prior sub-step.

Step 5: Calculate the base K-bar. Calculate the difference between the current year K-bar capital-related revenue requirement required on a projected basis (from Step 4) and the current year K-bar capital-related revenue requirement recovered in the base rates (from Step 3). The result is the capital funding shortfall or surplus amount for the current year.

Capital Supplements – F-Factor

Key Features:

- Utility forecasts its required capital-related revenue for the PBR term
- Only recovers this amount—cannot recover more if spending exceeds forecast



Advantages:

- Utilities receive their expected revenue shortfall for capital expenses, while still maintaining some incentive to contain those expenses.
- Reduces regulatory burden by setting the forecast before the term begins, and leaving any variances between actual and forecasted spending to be handled mechanistically through the ESM rather than through annual cost-of-service proceedings.

Disadvantages:

- May incentivize the utility to over-forecast capital expenses if it is able to retain any savings as profit.
  - This can be mitigated through prudency reviews before and after the PBR term.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

MAINE PUBLIC UTILITIES COMMISSION	**COMMENTS**
INQUIRY INTO PERFORMANCE-BASED REGULATION OF INVESTOR-OWNED TRANSMISSION AND DISTRIBUTION UTILITIES	**EFFICIENCY MAINE TRUST**
	MAY 30, 2025
DOCKET NO. 2025-00107	

Efficiency Maine Trust (hereinafter "the Trust") offers these comments in response to the Notice of Inquiry issued on April 30, 2025. In particular, the Trust is providing here comments related to the goals of Performance Based Regulation (PBR) set forth in the Christensen's draft report as requested by the Public Utilities Commission.

I. Goals of PBR in the draft report

The Trust recommends elements of the draft report that are not fully within the control or authority of investor-owned utilities either be removed from the report or be given the level of emphasis consistent with the utilities level of control. The Efficiency Maine Trust Act grants statutory authority to the Trust to develop, plan, coordinate, and implement energy efficiency, beneficial electrification and demand management programs across Maine. The draft report provides discussion and examples of PBR that are within the purview of the Trust and other entities.

For example, section 4.6 of the report discusses the potential of Performance Incentive Mechanisms (PIMs) to "…facilitate the deployment of distributed energy resources (DERs), and promote non-wire alternatives over traditional capital investments, among other objectives."[1] There are examples provided from other jurisdictions of PIMs that include non-wire alternatives, electric vehicle adoption rates, building electrification, and DER utilization.[2] While there are discrete tasks that the investor-owned utilities undertake to assist the Trust in implementing these objectives, for the most part it falls outside of their authority and the Trust recommends that these examples and other elements of the report that are within the purview of the Trust and other entities are removed or put into the appropriate context.

Respectfully submitted,

/s/IGB

Ian Burnes
Director of Strategic Initiatives
Efficiency Maine Trust

[1] Christensen's draft report, page 21.
[2] ibid, pages 24-29, tables 4.4, 4.5, 4.6.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

PUBLIC UTILITIES COMMISSION **RE: Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities** **Docket No. 2025-00107**	**COMMENTS OF THE OFFICE OF THE PUBLIC ADVOCATE** **May 30, 2025**

I. Introduction

The Office of the Public Advocate (OPA) files these comments pursuant to the Notice of Inquiry (NOI) into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities issued by the Public Utilities Commission (Commission or PUC) on April 30, 2025. Through the NOI, the Commission seeks input related to the goals of Performance Based Ratemaking (PBR), and the mechanisms by which the Commission could implement such goals. To address the implementation of PBR regulations, the OPA is submitting comments by Synapse Energy Economics, provided here as Attachment A. Below are the OPA's comments addressing the PBR policy goals as set forth in the draft Christensen Report.

II. Discussion of PBR Policy Goals

A. Review of Christensen Report Policy Goals

Section 7.3 of the draft Christensen Report identifies a version of regulatory goals for the state of Maine.[1] Most of these goals were articulated in a proposed statute, LD 2172, which did not pass, but are an indication of legislative intent.[2]

The draft regulatory goals are as follows:

1. Promote efficient and cost-effective transmission and distribution utility operations;
2. Increase planning and preparation for extreme weather events and climate hazards;
3. Promote cost-effective and comprehensive responses to outages;
4. Increase affordability and customer empowerment and satisfaction;
5. Support the achievement of the State's goals for increasing consumption of electricity from renewable resources;
6. Advance the State's greenhouse gas emissions reduction goals established; and
7. Advance beneficial electrification.

These goals encompass broad areas of policy for the state. PBR is one tool among many that may impact the state's ability to achieve these goals. It is only to the extent that utility actions can influence a policy goal cost-effectively, that they should be incentivized through a PBR mechanism.

Policy goals 1-3 address elements within a utility's current area of responsibility to provide safe and reliable utility service. Maine's existing utility Service Quality Indices (SQIs) are effectively Performance Incentive Mechanisms (PIM) that target these goals. Any additional PIMS for these goals would need to be narrowly tailored to target investment that would not otherwise take place under existing regulations.

Policy goal 4 is a fundamental goal that must be forefront in any exploration of PBRs. Borrowing language from the Hawaii PBR Guiding Principles, the goal of "customer empowerment" could be expressed more expansively as follows:

[1] Public Utilities Commission *Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities,* Notice of Inquiry, Docket No. 2025-00107 (April 30, 2025) Attachment A, (Christensen Report) at 72.

[2] [LD 2172, HP 1391, Text and Status, 131st Legislature, Second Regular Session]

> A customer-centric approach. A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers. [3]

Adding a separate goal of affordability would highlight the importance of this goal to ratepayers, such as "Increase affordability of utility rates such that arrearages and disconnections due to nonpayment are decreased as customer energy burdens are lowered."

Policy goals 5-7 are directed toward state climate policy goals. Any PBR tied to such goals must be narrowly tailored to be within the control of a wire-only utility and be a cost-effective approach toward meeting that goal. For example, ratepayers bear costs for Efficiency Maine Trust (EMT) programs which support goal #7, advancing beneficial electrification. It would be unjust for ratepayers to also pay for a utility PBR incentive program which is redundant of or possibly counter to existing EMT programs.

B. OPA Proposed Public Policy Goals

An effective PBR should strengthen the link between what utilities earn and the achievement of outcomes consumers value, such as cost effectiveness, reliability, customer service, and ensuring alignment with government policies. Borrowing language from the Ontario and Hawaii PBR principles referenced in the draft Christensen Report, a set of PBR goals for Maine that emphasize these outcomes could include the following:

1. A customer-centric approach. Encourage expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers.

2. Affordability. Increase affordability of utility rates such that arrearages and disconnections due to nonpayment are decreased as customer energy burdens are lowered.

3. Operational Effectiveness. Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.

4. Public Policy Responsiveness. Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements)

[3] *Id.* at 141.

5. Financial Performance: utility financial viability is maintained; and savings from operational effectiveness are sustainable.

III. Conclusion

It is challenging to design a PBR that incentivizes a utility to achieve identified goals without overcompensating the utility for perceived risks of moving away from cost-of-service regulation. The public policy goals expressed here are broad and may encompass objectives beyond the control of a utility. The Commission must ensure that any associated PBR targets are clearly defined and directly associated with the desired public policy goals. The Commission should ensure that the utility is in sufficient control of the variables associated with the public policy goals such that the targets create incentives for utility action. At the same time, such actions must not be considered a routine part of utility service that would be undertaken without the existence of a PBR mechanism.

While the state's public policy goals are appropriately broad, targets to incentivize utility contributions to these goals must be narrowly tailored and measurable to be effective within the confines of a PBR mechanism. As noted in the attached Synapse Report, the Commission should proceed cautiously in adopting PBR mechanisms "to ensure that the cure is not worse than the disease."

Respectfully submitted,

/s/ Susan W. Chamberlin

Susan W. Chamberlin
Senior Counsel

/s/ Brian T. Marshall

Brian T. Marshall
Senior Counsel

Performance-Based Regulatory Tools for Maine

Response to the Maine Public Utilities Commission's Request for Comments

Prepared for the Maine Office of the Public Advocate

May 29, 2025

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CONTENTS

INTRODUCTION

On April 30, 2025, the Maine Public Utilities Commission issued its *Notice of Inquiry* in Docket No. 2025-00107 requesting stakeholder input regarding the goals of Performance-Based Regulation (PBR) and potential enhancements to Maine's regulatory framework through performance-based tools such as Multi-Year Rate Plans (MYRPs) and Performance Incentive Mechanisms (PIMs).

Synapse Energy Economics, Inc. (Synapse) was retained by the Office of the Public Advocate (OPA) to respond to the draft report authored by Christensen Associates Energy Consulting (Christensen) and to generally comment on the potential for MYRPs and PIMs to promote public policy objectives while protecting consumers. Our assessment, described below, draws upon Maine's own regulatory experience, as well as our experience with PBR tools across North America.

OVERALL ASSESSMENT

Synapse has reviewed the draft Christensen report on PBR for Maine, and we find it offers a helpful description of PBR tools, as well as a useful description of some of the challenges associated with MYRPs and PIMs. We particularly agree with the report's admonition that "the introduction of new PBR tools will not guarantee improvements."[1] In theory, well-designed PBR frameworks can improve utility performance and better align utility incentives with public policy goals. However, real-world experience in Maine and elsewhere has shown that achieving these benefits in practice is far from assured.

MYRPs and PIMs are often promoted as a means of increasing efficiency and better aligning utility incentives with public interest goals. However, these mechanisms can also create perverse incentives and shift risk onto customers. MYRPs, for example, may result in unjustified revenue increases or incentivize excessive cost-cutting that undermines service quality. PIMs can lead to utilities being rewarded for actions they would have taken regardless of the incentive, or for outcomes influenced by external factors beyond their control. In these cases, customers bear the cost of incentives without receiving commensurate benefits.

Information asymmetries between utilities and regulators, combined with the complexity of designing balanced and enforceable incentives, make implementation of both PIMs and MYRPs challenging. Without careful design and oversight, PBR mechanisms can create unintended consequences that undermine regulatory outcomes and customer protections. Given these risks—particularly those

[1] Crowley, N., X. Wang, A. Romanovs-Malovrh, and C. Goodrich. Christensen Associates. Performance-Based Regulation Report for the Maine Public Utilities Commission. "Christensen Report." April 29, 2025. p. 1.

associated with MYRPs—Synapse recommends that the Commission proceed cautiously with further implementation of PBR mechanisms and ensure that strong customer protections, robust oversight, and data transparency are in place.

PIMs

Synapse agrees with the Christensen report's description of PIMs and acknowledges that additional PIMs could be designed to address various policy goals. However, we recommend that PIMs be implemented cautiously and be focused on policy goals that the utilities are most able to influence. We also concur with the report's conclusion that penalty-only PIMs are appropriate for areas within the core responsibility of the utility (e.g., providing safe and reliable service.)

Benefits of Metrics versus PIMs

As an initial matter, before implementing additional financial incentives in the form of PIMs, we recommend that the Commission focus on developing a robust set of performance tracking metrics. This approach would allow the Commission to provide the utilities with important information regarding its policy objectives, collect baseline data, evaluate the utility's performance, and identify areas in which current regulatory approaches are falling short—without introducing the risks that come with financial incentives.

Tracking metrics can also serve as a low-cost, low-risk tool to help achieve public policy goals, even where a full PIM is never established. For example, while the number of customers in arrears may not be suitable for a financial incentive (given that arrearages are also influenced by factors such as income levels and economic conditions), it remains a valuable metric. Tracking such data can help identify trends, inform utility and state program development (such as targeted assistance programs and arrearage management plans)—regardless of whether a PIM is ever applied to the metric.

To support effective use of performance metrics, we recommend that the Commission establish a standardized reporting process and centralized data repository. This would enhance transparency, reduce administrative burden, and facilitate stakeholder engagement by allowing for more efficient review and analysis of utility performance over time. It would also avoid the inefficiencies associated with ad hoc data requests and reactive analysis.

Affordability and Cost Efficiency

We also agree with the draft report's conclusion that PIMs generally do not aim to address overall utility cost efficiency,[2] but should be designed in concert with the underlying cost recovery framework (e.g.,

[2] Christensen Report, at 16.

MYRP or traditional cost of service regulation) so as to appropriately balance the incentives contained within the cost recovery framework. For example, if the utility operates under strong cost containment incentives, then higher financial incentives may be warranted for undertaking actions that the utility otherwise would not take (and which may temporarily reduce the utility's profits). Likewise, the current service quality indicators with penalties and offsets related to reliability and customer service are common across the industry and are particularly important for utilities under price-cap or revenue-cap MYRPs to guard against excessive cost cutting measures at the expense of service quality.

We also wish to note that although PIMs typically do not directly address affordability, metrics and potentially PIMs could be established to incentivize efficient operations by tracking various components of utility costs over time, such as "administrative and general expenses" per customer.

We also wish to underscore the concept that rewards and penalties should be proportionate to the value provided by the achievement of the PIM target, [3] *including the cost of achieving the PIM target*. For example, if the value of increasing performance by an increment is $500,000 and the cost of investments to achieve that incremental performance is $450,000, then the net value to customers is only $50,000. Any penalty or reward to the utility associated with achieving the additional reliability should be set below $50,000 to ensure that the achievement of the target provides benefits to customers. It may not always be possible to quantify the full cost or benefit of a PIM, but the utility and regulators should undertake the effort to understand the costs and benefits to the extent feasible.

Considerations for PIMs

To avoid over-compensating utilities and ensuring that metrics and PIMs provide value, we offer the following additional considerations for implementing PIMs:

- Are the desired public policy goals and associated metrics and targets clearly defined and measurable? It may take substantial stakeholder engagement to establish well-designed metrics and targets.
- Can these goals be achieved through existing regulatory mechanisms, or is a financial incentive necessary to spur improved performance?
- Is there a meaningful risk that utilities will not achieve these goals in the absence of a PIM? Utilities should clearly explain the barriers that prevent them from undertaking actions to achieve the goals and provide evidence regarding those barriers.

[3] Christensen Report, at 15.

MULTI-YEAR RATE PLANS

While MYRPs have the potential to create strong incentives for cost containment—thereby encouraging innovation and improving utility operating efficiency relative to traditional cost-of-service regulation—such outcomes are not guaranteed. If poorly designed, MYRPs can undermine the public interest by shifting risk to ratepayers, increasing overall costs, imposing additional regulatory burdens, or incentivizing under-investment.

Below, we examine two key challenges associated with MYRPs: accommodating capital investment and mitigating the risk of under-investment. This discussion draws on nearly two decades of experience with Central Maine Power (CMP) operating under a price-cap form of MYRP, known as an Alternative Rate Plan (ARP), from 1995 – 2013.[4] These ARPs operated as price caps, applying an "Inflation – X" formula to revenue increases.

These challenges discussed below highlight the need for the Commission to carefully evaluate the advantages and disadvantages of MYRPs relative to cost-of-service regulation before moving away from traditional approaches.

1.1. Treatment of Capital Costs

Overview

One of the most confounding problems associated with MYRPs is how to address capital costs when the traditional Inflation – X approach does not provide sufficient revenues to cover necessary investments. The Christensen report lists different approaches used by various states, including utility forecasts of capital spending, capital trackers, trends in the utility's historical capital spending, and project-specific recovery outside of the index formula.[5] The authors state that "the industry has not reached a consensus on capital recovery under PBR. Each approach to capital recovery gives rise to a certain level of complexity, risk, regulatory burden, and incentive pressure. However, the overarching similarity across PBR frameworks is that utilities have been granted means for recovering additional revenues, beyond what might be permitted under the I-X formula, in order to meet capital spending needs."[6]

Synapse generally agrees with Christensen's assessment that no mechanism offers a panacea in terms of effectively addressing capital cost recovery without introducing additional risks, distorting efficiency

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[4] Maine Public Utilities Commission. Order Approving Stipulation. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 25, 2014, at 1.

[5] Christensen Report at 44.

[6] Christensen Report at 45.

incentives, or increasing regulatory burden. We summarize below the risks to customers associated with each approach:[7]

- Capital trackers (K-Factors): These mechanisms reduce utilities' incentive to control costs, potentially leading to capital over-investment. Ironically, price cap MYRPs were originally proposed in part to end the use of cost trackers (or similar "balancing accounts"), which required regulators to rely increasingly on *ex post* prudency reviews, raising "the administrative cost of regulating the electric industry and the resources required for the Commission to perform adequately its regulatory obligations and responsibilities."[8]

- Utility forecasts: Forecasting can incentivize the utility to overstate spending needs and expected costs. Forecasts are notoriously challenging, as information asymmetry limits the ability of regulators and stakeholders to assess their accuracy and efficiency. This concern was noted by the Maine Public Utilities Commission when it rejected Central Maine Power (CMP)'s proposed forecast of capital costs, finding that CMP's proposal would "shift[] the risk of over estimation and uncertainty to the ratepayers."[9]

- Trends in historical capital spending (K-Bar): Not only does this approach rely on the assumption that past levels of investment are accurate predictors of future levels of investment,[10] it may also encourage the utility to continue increasing investment levels, as this will ensure its allowed capital revenue requirement continues to increase.

- Project-specific recovery: While potentially more targeted, this approach raises concerns about how to define and consistently apply qualification thresholds.

Additionally, treating capital costs separately from operations and maintenance (O&M) expenses overlooks the potential for capital investments to reduce O&M costs. As observed by the Maine Public Utilities Commission in 2013, "In effect, customers would be subject to increased capital costs while depriving them of the corresponding benefits of O&M savings."[11]

Experience in Maine

In May 2013, CMP proposed a new ARP, but with only operations and maintenance revenue requirements continuing to be subject to the traditional Inflation – X (I-X) formula. For capital revenue

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[7] *Ibid.*

[8] California Public Utilities Commission, Division of Strategic Planning. *California's Electric Services Industry: Perspectives on the Past, Strategies for the Future* (San Francisco, CA: California Public Utilities Commission, February 1993), at 153. Available at https://docs.cpuc.ca.gov/word_pdf/REPORT/3822.pdf.

[9] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 8.

[10] Christensen Report at 45.

[11] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 7.

requirements, CMP proposed a separate mechanism based on CMP's projections of capital costs, which would be subject to reconciliation and a sharing mechanism.[12]

The OPA filed a Motion of Partial Dismissal seeking dismissal of CMP's proposed capital reconciliation mechanism, arguing that the proposal to recover forecasted capital additions outside the traditional price index formula inappropriately shifts risk to ratepayers, while also placing unreasonable burden on the Commission and intervenors to scrutinize the forecasted capital projects and related costs.[13]

The Commission granted the OPA's motion, finding that CMP's proposal to recover capital costs based on a cost forecast would be inconsistent with the principles of both incentive regulation and cost-of-service ratemaking.[14] In dismissing the capital recovery mechanism, the Commission cited its own 1993 decision regarding the merits of including capital investments as part of the price cap formula to promote least-cost investment decisions and reduce the need for retrospective prudence reviews:

> A reason for not treating capital expenditures separately is that it would help eliminate the oft-discussed problem of ROR regulation giving firms an incentive to overcapitalize (the so-called "Averch-Johnson effect"). As an additional reason, by incorporating all capital expenditures for each category of resource … into the price cap formula, the company would have an incentive to make least-cost investment decisions. The Commission believes that such treatment of new capital expenditures should reduce the need for retrospective prudence reviews of CMP's planning activities.

The Commission found that, "By tying CMP's profits to the level of investments, the [capital recovery mechanism] removes one of the core objectives of an ARP, the elimination of the incentive to over-capitalize."[15]

Following this, CMP proposed a revised approach to incorporate its capital spending forecast into the I–X formula by introducing a K factor, which resulted in a negative productivity (X) factor. The OPA opposed this revision, instead recommending that major capital investments be addressed outside the I–X framework using traditional cost-of-service practices.[16] Ultimately, the Commission approved a stipulation in which CMP withdrew its ARP proposal and returned to cost-of-service regulation, with the

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[12] *Ibid.*

[13] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 3.

[14] *Id,* at 6.

[15] *Id,* at 7.

[16] Direct Testimony of Tim Woolf on Behalf of the Maine Office of the Public Advocate. Docket No. 2013-00168. December 12, 2013. . In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 25, 2014.

option to pursue a single-issue revenue requirement adjustment to recover costs associated with its new billing system.[17]

In summary, the inability of the traditional I–X formula to accommodate CMP's substantial capital investment plans posed a major obstacle to designing an ARP acceptable to all parties without imposing undue risk on customers. This challenge remains relevant today, particularly given similar concerns associated with capital recovery mechanisms in other MYRP frameworks.

1.2. Under-Investment

By enforcing a stay-out period and allowing utilities to keep some or all of the profit from managing costs below its revenues, multi-year rate plans increase utilities' incentives to operate efficiently. However, this incentive can result in under-investment in infrastructure in order to increase short-term profits.[18]

The Commission raised this concern in 2013 in response to Central Maine Power's request to substantially increase its capital spending after a long period of operating under a price cap MYRP. In particular, the Commission noted that a multi-year rate plan "could provide the utility with an opportunity to allow its system to degrade in order to keep profits high," and that such a possibility may need to be addressed in the rate case.[19]

In response to this concern, Commission Staff analyzed CMP's historical spending compared to its projections. Staff found that it was "difficult to assess whether more recent spending reflects a catch-up for projects that should have been done in earlier years," but that "a significant number of projects" were now necessary because many issues had been deferred or not addressed, including projects "identified in recent years that might be considered high priority."[20] In conclusion, Staff found that the substantial increases in capital spending compared to prior years "raises questions about whether projects that should have been undertaken under prior ARPs have been deferred to the benefit of CMP's shareholder[s]," and the "extent to which the prior ARPs were failing to provide the correct incentives for CMP to make plant investments."[21] These findings contributed to Staff's recommendation to take a "hiatus" from CMP's alternative regulation plan in 2013 and return to cost-of-service regulation.

[17] Maine Public Utilities Commission. Order Approving Stipulation.

[18] Armstrong, M. and D.E.M. Sappington (2006), "Regulation, Competition and Liberalization," *Journal of Economic Literature*, 44(2), pp. 325-366.

[19] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 83.

[20] Maine Public Utilities Commission Staff. Bench Analysis. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. December 12, 2013, at 25.

[21] *Id.,* at 36.

1.3. Experience in other Jurisdictions

Synapse is aware of at least two jurisdictions currently undertaking a review of the efficacy of MYRPs: Maryland and the District of Columbia. The Maryland Office of the People's Counsel (OPC) has put forward a harsh critique of the state's foray into MYRPs, finding that the structure has resulted in average annual rate increases of more than 6 percent since the implementation of MYRPs, reflecting both accelerated capital investments as well as increased operations and maintenance spending.[22]

Notably, the Maryland MYRP construct is heavily reliant on utility cost forecasts, with provisions allowing for reconciliation to actual, prudently incurred costs. This approach significantly weakens cost-containment incentives for utilities while increasing the regulatory burden on agencies and intervenors tasked with scrutinizing forecasted expenditures.

Regarding cost containment incentives, the Maryland OPC argues that the MYRP structure:

> …drastically lower the risk to utilities posed by cost-ineffective operations through the reduction of regulatory lag and the approval of proposed capital projects for revenue requirement purposes. The very design of the [MYRP]—basing rates on utility-proposed budgets of a forecasted three-year plan—incentivizes utilities to "shoot for the moon" and pursue a greater number of capital investments than what would have been pursued under standard ratemaking, which is based on actual spending during a historic test year. The opportunity to reconcile both O&M and capital costs—and recover costs incurred above authorized budgets—substantially lowers utility risks associated with inaccurate forecasting, poor performance, mismanagement, or cost-ineffectiveness. These risks—including reduced profitability for cost-ineffectiveness and cost-disallowances for untimely and unnecessary investments—are instead shifted to customers.[23]

In terms of administrative burden, the OPC observes:

> "No evidence demonstrates that the administrative burdens imposed by MRPs are lighter than standard ratemaking burdens. Rather, experience shows that MRP cases have *increased* administrative burdens for stakeholders."

Maryland's experience provides a cautionary example of the potential pitfalls of poorly-designed MYRPs. However, as highlighted earlier in this report, it is difficult to design an efficient MYRP that provides sufficient revenues to the utility but minimizes risk to ratepayers. This underscores the importance of carefully evaluating any departure from cost-of-service regulation to ensure that the cure is not worse than the disease.

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[22] Maryland Office of the People's Counsel. Initial Comments. Case No. 9618 and 9645. September 16, 2024, at 1-2.

[23] Maryland Office of the People's Counsel. Initial Comments. Case No. 9618 and 9645. September 16, 2024, at 2.

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ELECTRONICALLY FILED ON MAY 30, 2025

May 30, 2025

Amy Dumeny, Administrative Director
Maine Public Utilities Commission
26 Katherine Drive
Hallowell, ME 04347

Re: MAINE PUBLIC UTILITIES COMMISSION Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities, Docket No. 2025-00107.

Dear Ms. Dumeny:

On behalf of Versant Power ("Versant"), enclosed please find Versant's Initial Comments in response to the April 30, 2025 Notice of Inquiry.

If you have any questions, please do not hesitate to contact me.

Sincerely,

David P. Littell

c: Service to Active Party List via MPUC e-notification

STATE OF MAINE **PUBLIC UTILITIES COMMISSION**	**May 30, 2025**
	Docket No. 2025-00107
PUBLIC UTILITIES COMMISSION **Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities**	**VERSANT POWER INITIAL COMMENTS**

Versant Power ("Versant" or the "Company") submits these comments in response to the Notice of Inquiry (the "Notice") that the Maine Public Utilities Commission (the "Commission") issued on April 30, 2025. This Notice initiated the Commission's inquiry, pursuant to 35-A M.R.S. § 1301(1), to receive stakeholder input into the Commission's examination and development of performance-based regulatory tools for investor-owned transmission and distribution ("T&D") utilities.

I. BACKGROUND

The Notice indicates the Commission is examining and intending to develop specific regulatory tools focusing on performance-based regulation ("PBR"). Christensen Associates Energy Consulting ("Christensen") was retained to assist the Commission in its investigation of PBR for the state's electrical utilities. Christensen prepared a draft report (the "Report") that accompanied the Notice, presenting Christensen's findings and recommendations of PBR for Maine.

The Report observes that Maine already has experience with performance incentive mechanisms ("PIM") in the form of negative incentives, also known as penalties, associated with service quality standards and metrics adopted under Chapter 320 of the Commission's rules. As briefly summarized in the Notice and fully in the Report, multi-year rate plans ("MYRP") and PIMs are two different forms of PBR. MYRPs and PIMs are neither mutually exclusive nor mutually dependent forms of PBR.

II. VERSANT COMMENTS

Versant appreciates Christensen for providing a fulsome report on what advanced PBR and specifically an advanced third or fourth generation MYRP may look like in the future. Regarding the Report's recommendations on PIMs, Versant agrees with the suggestion that approaches to PIMs should be symmetric. Opportunities to receive performance rewards or offset negative PIMs with positive PIMs would be beneficial in setting up well-balanced guideposts for utility performance under a PBR plan.

Versant welcomes the opportunity to engage in discussions on the development of PIMs, including the establishment of metrics and baseline data, to ensure that resulting metrics are both measurable and meaningful. To attach a performance incentive, whether positive or negative, the performance needs to be measurable, within the control of the utility, and within reasonable reach of meeting the performance standard set by the performance metric. Versant notes the Report may underemphasize the importance of getting the metrics set to properly measure the desired outcomes and performance.

Testing metrics and evaluating them against performance is a sound scientific approach to getting the measurement performed by the metric correct. For example, if the Commission is interested in evaluating and measuring peak load reductions as a result of utility rate design or Distributed Energy Resources (two different potential goals in measurement), a peak reduction can be measured as a function of kW/MW peak(s) from the utilities prior period peak(s) for that month, or average/median peak for that month for the last two years, or seasonally, or measured as a percentage of peak reduction from a projected peak assuming load growth at a specific level or derived from peak projected by ISO New England ("ISO-NE") annually. There may be reason to adjust for heating and cooling days as well as making other conforming adjustments. Each measure can be reduced to a formula, and each is a valid measure of peak reduction, but some formulas would likely fit better to the purpose for measuring peak reductions for the intended purpose. ISO-NE, of course, has (or had) a specific measure to apply for peak reductions in the context of dispatched demand-response ("DR") that is suited to ISO-NE purposes of measuring how much activated DR operates to meet its committed peak reduction from a pre-established baseline for the DR resource. That peak reduction measure is aligned to the ISO-NE specific programmatic purpose and is probably not the right peak reduction metric for a utility if the Commission desires to measure peak reduction from utility deployed measures. Refining the purpose, the metric and the metric's formula to measure performance requires attention, analysis, and sometimes testing.

Availability of good underlying data to measure is also critical. In some instances, that underlying data may exist and in other instances that data will need to be collected. Data needs to be reliability collected, maintained, and undergo quality assurance and quality control procedures. Versant notes the Report may understate the need to identify, collect, and maintain baseline data in establishing appropriate PIMs and suggests this topic may benefit from further discussion. If data does not exist, the utilities can—assuming it is reasonably available—begin to collect it. Refining data needs similarly involves attention, analysis, and sometimes testing.

To set a PIM appropriately requires a realistic and meaningful performance standard—typically a metric expressed as a goal—which builds on a reliable set of baseline data. The Company views the use of initial report-only PIMs likely to be extremely helpful in this regard. Having T&Ds initially report only data-reporting PIMs can serve as a practical starting point for collecting and analyzing data, as well as testing certain measurement methodologies and data sets. Through the collection of data and testing of analytical methods and performance measures, baseline data and metrics can be evaluated. This process should assist the Commission, the utilities, and stakeholders in developing a shared understanding of the goals and how progress toward those goals will be measured.

Versant is interested in exploring effective approaches to measuring system resilience and greenhouse gas ("GHG") reductions—areas where performance tracking can meaningfully support both customer outcomes and state policy objectives. In the case of GHG reductions, Maine's Electric Distribution Companies ("EDC") no longer operate generation assets, which may limit direct emissions reduction opportunities compared to jurisdictions like Hawaii or Minnesota, where EDCs continue to generate electricity. That said, there may still be meaningful opportunities to assess emissions impacts associated with Versant's programs or operations. Versant looks forward to working collaboratively with the Commission and other stakeholders to examine these possibilities.

As the Report illustrates, there is a good deal of work and analysis that goes into developing a MYRP. Versant also observes that a MYRP and other PIMs serve distinct functions and use different PBR mechanisms. Neither a MYRP nor PIM regime require adopting the other. As the Report highlights through examples from Minnesota and Hawaii, developing a comprehensive PBR plan typically takes years of collaboration among regulators, utilities, and stakeholders. Versant seeks to ensure that any MYRP supports the Company's goal of enhancing distribution system reliability and overall system resiliency, including the ability to respond and recover from increasingly frequent and severe storm events and other system disruptions.

Finally, Versant emphasizes the need for efficiently-focused management attention. While large numbers of PIMs and priorities may dilute focus, a more streamlined set of MYRP and/or PIM goals and measures can be useful to focus management attention if that is the Commission's goal.

Versant is focused on delivering a more reliable and resilient power system. Versant is equally committed to achieving this in ways that support the State's GHG and other broader environmental goals. To that end, Versant favors a MYRP and PIM approach that enables a continued focus on providing reliable, resilient, and clean energy to its customers (noting that Versant does not provide electrical supply but only delivery service).

III. CONCLUSION

Versant remains committed to supporting the Commission's examination of the effectiveness of PBR goals, metrics, and PIMs in achieving its own and Maine's policy objectives. The Company advocates for a methodical approach that balances the benefits to Maine residents with the costs to customers, focusing on investments in the highest priority areas. Versant appreciates the Commission's consideration of these comments.

Dated: May 30, 2025

Respectfully submitted,

Versant Power
By its attorneys,

/s/ Arielle Silver Karsh
Arielle Silver Karsh, Esq.
Senior Regulatory Counsel
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/s/ David P. Littell
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STATE OF MAINE | Docket No. 2025-00107

PUBLIC UTILITIES COMMISSION

May 30, 2025,

PUBLIC UTILITIES COMMISSION | **COMMENTS OF AARP MAINE**

Inquiry into Performance-Based Regulation of Investor-Owned Transmission and Distribution Utilities

AARP Maine is pleased to provide comments on the performance-based ratemaking (PBR) discussion.

AARP is no stranger to the issue nor to Christensen and Associates who is managing a similar endeavor for the Indiana Utility Regulatory Commission where we have also sent comments to them and to the Commission. (A report to the Legislature is being prepared. Comments are due July 16).

Nor is AARP a stranger to the PBR issue. We have helped nix similar efforts in Michigan and other states. While appealing at the 60,000-foot level, the proposal is too complex to administer, rewards utilities for things they should already be doing, and worse. This is why few U.S. states have adopted it after similar regulatory or legislative reviews.

AARP supports a few targeted performance incentives to keep rates affordable and service reliable. PIMS should be done on a pilot basis. They should be symmetrical (penalties or rewards).

Indeed, Maryland just passed a new law allowing multiyear rate plans (part of the PBR discussion) ONLY if benefits to ratepayers can be demonstrated. The state found that multiyear rate plans encouraged utilities to file 3- or 4-year wish lists of spending, causing rates to soar. Maine should heed the lessons of Maryland.

AARP is also opposing the proposal of Eversource in New Hampshire to adopt a complicated PBR scheme including the capital cost tracker affectionately known as KBAR. It is turning out to be too complex and parties to the proceeding (filed in their rate case) have numerous problems with it.

PBR means many things to different people: a rate case that spans several years and relies on speculative/forecast costs, performance incentives (rewards) for meeting things like providing excellent customer service, formula rates (or index rates) with adjustors such as capital cost trackers (KBAR) and more. The fact that one state has adopted 3-year rate cases does NOT mean it has embraced all of the other types of PBR.

In short, PBR is still an untested alternative in terms of benefits to consumers.

Our comments to Christensen and the Maine PUC are similar to those we filed in Indiana and other states and are as follows:

- Are the proposed policy goals appropriate for guiding the design of a regulatory framework in Maine? ANSWER: No. These goals should come from the legislature as proposed. The PUC should focus on maintaining affordable and reliable service.
- Are there nuances to the current regulatory framework in Maine that are not fully reflected in the Christensen report? ANSWER: Yes. PBR is a solution in search of a problem.
- The fact that California has had 3-year rate cases does not mean it uses PBR. It does not. Maine utilities can already file 3-year rate cases and propose service quality indicators. It is unclear what problem we are solving.
- Regarding formula rates, they have been a disaster for consumers as Illinois learned in its 11-year experiment. There is no reason to adopt a similar scheme (indexed rates with KBARs, etc.) in Maine.
- Is an expansion of PIMs in the state appropriate? If so, how should they be developed? ANSWER: No. AARP favors targeted use of PIMs which is already done using service quality indicators. However, they should not be easy to meet targets and penalties and rewards should be used (symmetrical). They should also be easy to measure. Oftentimes the utility alone has the data to measure meeting the target.
- For the utilities: what guidance do you need from the Commission before putting together a rate application with PBR tools that are not currently used in Maine? ANSWER: Utilities should not be allowed to pursue PBR beyond the tools they already have (multiyear rate cases, service quality indicators, and the like).

<u>Other comments of AARP</u>

The proposed KBAR capital cost tracker is detrimental to ratepayers. It is too complicated. It should be rejected.

The Commission should commence a study of the problems with PBR before going further. This includes why California returned to traditional regulation after briefly trying PBR in the 1990s, why Minnesota spent 3 years developing over 100 PIMs and still has not implemented it, the problems with formula rates in Illinois, Alabama, and other states that have caused rates to soar, etc. We appreciate this opportunity to comment.

Sincerely,

Noël Bonam

noël bonam

State Director
AARP Maine

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2025-00107

May 30, 2025

MAINE PUBLIC UTILITIES COMMISSION,
Inquiry into Performance Based Rates Regulation of Investor-Owned Transmission and Distribution Utilities

CENTRAL MAINE POWER COMPANY COMMENTS

I. **BACKGROUND**

On April 30, 2025 the Maine Public Utilities Commission ("MPUC" or "Commission") initiated an Inquiry into Performance Based Rates Regulation of Investor-Owned Transmission and Distribution Utilities ("Inquiry") pursuant to 35-A M.R.S. § 1303(1). The Inquiry seeks input from stakeholders on development of performance-based ratemaking ("PBR") tools. The MPUC held a workshop on May 14, 2025 where Christensen Associates presented their draft report, Performance-Based Regulation Report for the Maine Public Utilities Commission ("Report") and participants provided input on the goals of PBR and the draft report. CMP actively participated. The procedural schedule in this Inquiry does not provide an opportunity for stakeholders to comment on the final report; CMP suggests, such comment opportunity could be a valuable final step and would contribute comments.

Notably, the concept and application of PBR incentives and mechanisms has been available in Maine and throughout most States for more than two decades. Indeed, the MPUC's current regulations afford opportunities to implement performance metrics to drive utility accountability and performance. MPUC Rule, Chapter 320, Electric Transmission and Distribution Utility Service Standards contains both performance metrics and reporting requirements. Chapter 320 required by LD 1959, established extensive metrics to measure utility Reliability, Customer Service and Operations. Specifically, the Reliability metrics measure the length of the average customer interruption (CAIDI), the frequency of interruptions (SAlFl), the total hours an average customer was without power (SAIDI), and the Feeder Adder Interruption Frequency Index (FAIFI) for circuits that performed poorly by comparison to the rest of the system. Customer Service metrics measure how many customer calls are answered within 30 seconds (85% in 2023), how many callers hang up before being answered, how many callers cannot reach the Company when they call, how accurate and timely customer bills are issued, and how many customers have bills based on actual reads instead of estimates. Operations metrics identify how many customers had their new construction completed and energized by their Customer Guarantee Date. Each of these metrics and their associated targets were determined in a lengthy and collaborative proceeding and then approved by the Commission

In addition, CMP's current rate plan, approved in Docket No. 2022-00152 is a two-year rate plan that includes several attributes of PBR regulation including a service quality indices revenue adjustment mechanism, earning sharings, revenue decoupling and also that it is a multi-year plan. Despite this history, and active application of performance-based mechanisms, CMP strongly supports the work being done by the Commission pursuant to the law to gain further input on appropriate PBR tools and appreciates the opportunity to participate in this process.

II. CMP COMMENTS ON REPORT FROM CHRISTENSEN ASSOCIATES

The Christensen Report extensively and fairly presents fundamentals of rate regulation, fundamentals of PBR regulation, and reviews the tools and mechanisms available to regulators. Final recommendations are forthcoming in the next draft of their document. Overall, CMP views the draft report as a valuable launching off point for the next phase of PBR regulation in Maine, in particular, providing a common set of terms and definitions, and optionality for regulators as they design rates for utilities. This last point is the cornerstone of CMP's comments, namely there is no one-size-fits-all approach to PBR. Instead, common understanding on the tools and their usefulness and application, will allow regulators, stakeholders, the public advocate and the T&D utilities to work to an outcome for each IOU in Maine that achieves strong utility performance, and stronger customer outcomes. A healthy utility will lead to better outcomes for customers and PBR is an ideal way to meet those two, seemingly divergent, but actually symbiotic outcomes.

A. Comments on Christensen Report "Proposed Policy Goals in Maine"

The Report listed the following seven goals for PBR in Maine. CMP lists them and notes its view on the goal below. CMP views these goals as guiding principles and not regulatory imperatives and would oppose strict requirements in any one category. Also, CMP does not support the inclusion of goals that are outside its ability to control. Utilizing PBR mechanisms will lead to rate plans that advance each of the stated goals in a tailored manner for the utility.

1. <u>Promote efficient and cost-effective transmission and distribution utility operations</u> – CMP agrees the cost-effectiveness should be one of the top priorities as customers expect and deserve efficient delivery of safe and reliable service at reasonable rates.
2. <u>Increase planning and preparation for extreme weather events and climate hazards</u> – CMP agrees that anticipating and planning for extreme weather events is an essential goal given the increase in severity and frequency of extreme weather events causing customer outages and widespread damage to the CMP transmission and distribution system.
3. <u>Promote cost-effective and comprehensive responses to outages</u> – CMP agrees, and this goal closely aligns with #2 above – by planning for extreme whether CMP will be in a better position to respond effectively. CMP notes that inclusion of timely response as a

component of the goal could be important to customers, as customers increasingly expect rapid restoration and reduced outages.

4. Increase affordability and customer empowerment and satisfaction – CMP agrees that customer empowerment and satisfaction is a reflection of a well-run utility and an engaged customer base. Regarding affordability, this is closely aligned with goal #1 above that aims to achieve cost-effective operations. Notably, affordability is an additional consideration beyond cost-effective rates, and may be subjective. The balance between investment in the system, strong operations and affordability is a challenge, and PBR mechanisms can assist in finding the suitable balance for a particular utility at a given time.

5. Support achievement of the State's goals for increasing consumption of electricity from renewable resources – CMP supports state's renewable energy goals and does not oppose the inclusion of support for such state goals in the list of considerations. These goals are subsidiary to the threshold drivers of safe, reliability, and cost-effective service at reasonable rates, but should be included in consideration. Aspects of this goal that are strictly beyond a utility's control, should not be central to regulatory decision making.

6. Advance the State's greenhouse gas emissions reduction goals – CMP supports the reduction of greenhouse gas emissions but questions the appropriateness of including this as a goal for a utility rate plan as this may not be measurable and/or within the control of the MPUC or the utility. CMP is open to keeping this goal on the table, but notes that goals #1-#3 above should take priority for purposes of establishing rate plans that benefit customers from a performance and cost-effectiveness perspective.

7. Advance beneficial electrification – CMP supports beneficial electrification and reiterates the same points it made above, regarding measurability, utility performance and cost-effectiveness.

B. Comments on Christensen Report Recommendations

CMP agrees that the Report identifies all the key categories for designing a PBR. Rather than providing detailed suggestions in each category at this stage, CMP encourages a dynamic set of recommendations that gives some leeway to the MPUC to pick and choose different mechanism to blend together and achieve their goals. Although not established in the procedural schedule, CMP would welcome the opportunity to weigh in on the final recommendations if that would be of use to the MPUC in its process.

Respectfully Submitted,

Carlisle Tuggey
General Counsel
Central Maine Power Company

MAINE LEGISLATURE

STATE HOUSE STATION
AUGUSTA, MAINE 04333

April 18, 2024

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018

Dear Chair Bartlett, Commissioner Gilbert and Commissioner Scully:

We are writing to urge the Public Utilities Commission to proactively implement the performance-based regulatory framework outlined in L.D. 2172, An Act to Enhance Electric Utility Regulation Based on Performance, despite the absence of legislation.

As you know, L.D. 2172 would have established a framework for the Commission to develop comprehensive regulatory reforms, based on performance, for electric utilities to better align regulation with Maine's climate and grid modernization goals. Should new legislation be proposed in the 132nd Legislature, it would only be effective in September of 2025, resulting in a proceeding beginning sometime in 2026. Any consequential results likely would not be realized until early 2028. We do not have time to wait that long.

We understand the Commission already has the authority to initiate this process under the existing statutory provisions.

We respectfully request the Commission to take the following actions:

<u>Initiate a Proceeding</u>: Commence a proceeding to examine and develop performance-based regulatory tools for investor-owned transmission and distribution utilities. This proceeding should involve robust stakeholder engagement, including workshops and public hearings to gather input from diverse perspectives.

<u>Establish Performance Goals and Standards</u>: Define clear goals for utility performance that are consistent with the objectives of the state's climate action plan and the integrated grid planning proceedings. Translate these goals into standards that might be used as the basis for metrics that could be applied in future rate cases.

<u>Report to the Legislature</u>: Provide a report to the Legislature, ideally before the end of the first session of the 132nd Legislature, on the progress of the proceeding, including recommendations

for any necessary legislative action to further enhance the effectiveness of the performance-based regulatory framework.

Voluntarily initiating a process now, with a report on any necessary legislation, will allow for the broadening of regulatory reforms that began with L.D. 1959 in the 130^{th} Legislature to proceed without delay.

We welcome the opportunity to discuss this matter further, and to provide any additional information or support the Commission may require.

We appreciate your consideration.

Sincerely,

Gerry Runte	S. Paige Zeigler	Senator Mark Lawrence
Maine House District 146	Maine House District 40	Maine Senate District 35