Comprehensive multi-year rate plan structures

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1 List of Acronyms

ACM	Advanced Capital Module
ADA	Advanced Distribution Automation
AER	Australian Energy Regulator
ARM	Attrition Relief Mechanism
AUC	Alberta Utilities Commission
BCUC	British Columbia Utilities Commission
BEV	Battery Electric Vehicles
CAPEX	Capital Expenditure
CIP	Capital Investment Plan
CMP	Central Maine Power Company
COS	Cost-of-Service
DER	Distributed Energy Resources
DG	Distributed Generation
DPU	Massachusetts Department of Public Utilities
DSM	Demand-Side Management
DSP	Distribution System Plan
ED1	Electric Distribution 1
EIA	US Energy Information Administration
ESM	Earnings Sharing Mechanism
ETR	Estimated Time of Restoration
EV	Electric Vehicle
GMF	Grid Modernization Factor
GMP	Grid Modernization Plan
ICM	Incremental Capital Module
IQI	Information Quality Incentive
IR	Incentive Regulation
IRM	Incentive Rate Mechanism
ISA	Interconnection Service Agreement
MPUC	Maine Public Utilities Commission

MRP	Multi-year Rate Plan
NYPSC	New York Public Service Commission
O&M	Operations & Maintenance
OEB	Ontario Energy Board
OFGEM	United Kingdom Office of Gas and Electricity Markets
OM&A	Operating, Maintenance, and Administration Expenses
PBR	Performance-based Regulation
PHEV	Plug-in Hybrid Electric Vehicles
PIM	Performance Incentives Mechanism
REV	Reforming the Energy Vision
RIIO	Revenue = Incentives + Innovation + Outputs
ROE	Return on Equity
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TNB	Tenaga Nasional Berhad
TOTEX	Total Expenditure
UK	United Kingdom

2 Executive Summary

On August 11, 2022, the Central Maine Power Company ("CMP" or the "Company") filed its multi-year rate plan ("MRP"). London Economics International LLC ("LEI") was retained by the Maine Public Utilities Commission ("MPUC" or "Commission") to assist in examining incentives to invest in CMP and related ratemaking and performance incentive mechanisms. This report specifically has four tasks, namely to (i) identify MRP features used in other jurisdictions; (ii) provide examples of approaches used to assess utility expenditures and prudent spending; (iii) review how capital trackers work and how criteria for capital trackers are set in other jurisdictions (specifically in Alberta); and (iv) provide examples of performance incentive mechanisms ("PIMs") related to distributed energy resources ("DERs") and distributed generation ("DG"), utility responsiveness to field requests, and storm response. MRPs are a common approach to performance-based regulation ("PBR"), or a regulatory framework designed to incentivize improved utility performance. The core features of an MRP include a moratorium on general rate cases combined with an attrition relief mechanism ("ARM"), which allows the utility's revenues or rate cap to increase when the utility faces external pressures. Other characteristics of the MRP include provisions for (i) trackers to account for costs not addressed under attrition, (ii) revenue adjustments that allow the utility to recover costs incurred as a result of events outside of management control, and (iii) PIMs to ensure that service quality does not decline while the utility practices cost control. When designed well, MRPs should strengthen cost containment, provide incentives to ensure good utility performance, and reduce administrative burden in the long term.

Performance incentives are often used along with efficiency incentives to ensure that any implemented cost reductions will not undermine reliability and customer service standards, nor result in service quality deterioration. For example, the Philippines adopted a price-linked incentive scheme in order to ensure good service quality. Under this scheme, the utility's performance during the regulatory term partially impacts its revenue requirement for the following year. If the utility performs above expectations, it will be allowed to increase (up to a cap) its revenue requirement.

Moreover, under an MRP, and more specifically under a cost forecasting approach (or building blocks approach), the onus is on the utility to prove that forecasts are accurate. Jurisdictions that use the cost forecasting approach, such as Australia, Malaysia, and the United Kingdom ("UK"), evaluate the utility's forecasts (or business plan) and spending by performing ex-ante and ex-post reviews. For example, these jurisdictions use analytical tools like trend analysis, benchmarking, technical engineering reviews, and economic and statistical techniques for their ex-ante reviews. Instead of undertaking comprehensive reviews of utility spending, Massachusetts uses an indexing rate formula that allows the base rate to increase by an inflation factor less a pre-determined and fixed productivity factor during the regulatory term. Massachusetts then performs prudence reviews of expenditures that are outside of the indexing rate formula (called capital trackers). These examples show that prudence reviews, or reviews of utility spending, remain important under the MRP.

LEI was asked to look at mechanisms used in other jurisdictions that ensure that a utility is not inflating its costs. One such mechanism (used in New York and Minnesota) is the clawback mechanism. This mechanism reduces the utility's propensity to inflate its cost projections and protects customers from utility underspending. However, it does not prevent the utility from inflating its capital projections and provides no incentive to increase efficiency. It also increases administrative burden for both the utility and the regulator. A more complex mechanism used is the UK's information quality incentive ("IQI") scheme, which rewards high-quality and well-justified business plans and accurate expenditure forecasts and penalizes forecasts that differ significantly from actual spending. Although the scheme incentivizes utilities to submit more accurate forecasts, designing an IQI scheme requires various analyses and significant effort both from the regulator and the utilities.

Although capital trackers are a common feature under an MRP, LEI's research shows such trackers should be limited to a few specific items, so as not to undermine the MRP's incentive properties. Recognizing that the indexing rate formula was insufficient to fund necessary capital expenditure ("capex"), the regulators in Alberta and Ontario set up specific criteria under which spending can qualify for a capital tracker. Alberta's criteria specify that the expenditures must be outside of the normal course of ongoing operations, for the replacement of existing capital assets or required by an external party, and have a material effect on the utility's finances. Likewise, Ontario set criteria on materiality (must exceed the threshold set by the regulator), need (must pass a means test and must be a discrete project), and prudence (must prove that it is the most cost-effective option). Massachusetts' Grid Modernization Plan ("GMP") has a capital tracker that monitors the utilities' performance through various metrics on pre-authorized investment categories.

Finally, as part of the scope of work, LEI provides examples of PIMs related to (i) DERs and DG, (ii) responsiveness of utilities to field requests, and (iii) storm response. DER/DG PIMs are either tracked by utilities or carry financial rewards that incentivize support of a state's environmental, emissions, and/or energy efficiency goals and programs. They specifically seek to increase the speed with which DER/DG systems interconnect with the grid and the number of customers participating in DER/DG programs. Responsiveness PIMs may include, but are not limited to, tracking of calls answered within a specified time, the amount of time it takes the utility to address customer concerns, and interconnection experience, to name a few. These aim to ensure that customer needs are met quickly and efficiently. In terms of storm response metrics, New York has applied a so-called scorecard that tracks the utilities' performance before, during, and after a storm. The data collected with the scorecard will be used to develop a quantitative tool that the utility and the regulator can apply to assess the utility's performance in restoring electric service during outages resulting from major storms or other such events. The process through which New York is looking to establish a storm response tool also makes for an interesting case study.

3 Scope of work

On May 26, 2022, CMP filed its *Notice of Intent to File a General Rate Case* in Docket No. 2022-00152, noting that it expected to propose a three-year rate plan.[1] At the same time, the MPUC has been concerned about CMP's service quality. It commissioned an independent audit report, filed in Docket No. 2018-00194 and Docket No. 2021-00303. The audit found several processes and issues at CMP's corporate parents (Avangrid and Iberdrola) which could negatively affect CMP and its customers:[2]

- high turnover and cost-cutting at top levels in Avangrid and Iberdrola negatively impacted operational experience, organizational stability, and staffing levels at CMP;
- governance-related issues, including the makeup and focus of the Iberdrola, Avangrid, and CMP Boards of Directors, were found to be below industry standards for US utilities; and
- planning and budgeting processes and decisions reside at the Avangrid Networks level have negatively impacted CMP.

In Docket No. 2022-00038 *Investigation of Central Maine Power Company Management Issues and Related Ratemaking and Performance Incentive Mechanisms*, the Commission began the process of investigating how CMP and its customers were affected by decisions concerning earnings, capital budgeting, and planning made by CMP's corporate parents. Ultimately, the Commission's goal was to determine whether the rate plan which CMP was expected to propose in Docket No. 2022-00152 would be more suitable than the current cost-of-service ("COS") rate plan under which CMP operates, given Avangrid/Iberdrola's incentives to invest in CMP.

Given this context, LEI structured this report to focus on the following:

1. identify features of MRPs used in other jurisdictions;
2. review approaches used in other jurisdictions to evaluate whether a utility's expenditures have been made prudently, as well as approaches used to assess the prudence and benefit of utility spending;
3. describe how capital trackers work and how criteria for capital trackers are set in other jurisdictions; and
4. provide examples of PIMs or other performance metrics or mechanisms in three categories: DERs and DG, utility responsiveness to field requests, and storm response.

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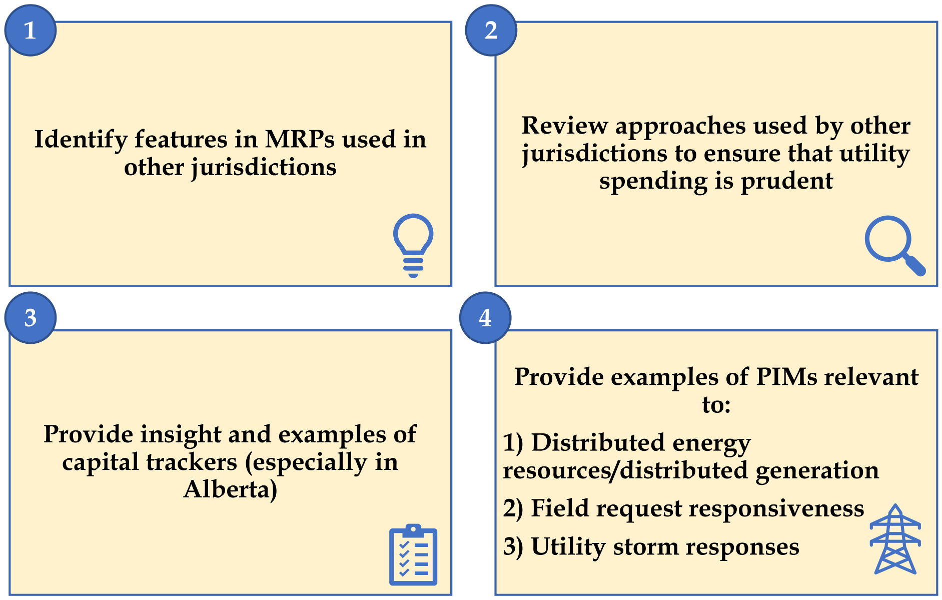
[1] Central Maine Power Company. *Notice of Intent to File a General Rate Case*. Docket No. 2022-00152. May 26, 2022.

[2] Liberty Consulting. *Final Report Central Maine Power's Management Structure and Affiliate Services*. July 12, 2021.

Figure 1. LEI's four key tasks as part of this scope of work



These key tasks are intended to help MPUC evaluate CMP's proposal in this rate case—under what categories of PBR or the MRP its proposal falls, and the proposal's gaps compared to a comprehensive MRP framework.

Though the MRP can be a complex regulatory framework, if implemented comprehensively, it can incentivize cost containment on the part of the utility as well as support reliability, innovation, and benefits to ratepayers, among others. A combination of MRP elements—where elements should be context-specific and chosen based on the needs of the jurisdiction—can help create a regulatory framework that addresses a utility's, regulator's, and customer's key concerns. Implementing the MRP in part and not in whole (i.e., without key complementary elements) may have the opposite effect.

4 Overview of CMP's proposed multi-rate year plan

CMP filed its initial rate case on August 11, 2022.[3] The proposed three-year rate plan—based on CMP's forecasted capital investment plan—is intended to fund "investments needed to improve reliability and resiliency, as well as to improve the customer experience and cost-effectively advance clean energy transformation,"[4] as well as to protect against rate volatility and avoid the time and cost of repeated rate cases.[5] CMP argues that the distribution system needs substantial increases in capital investment and that the MRP will provide transparency and timely capital investments that will keep debts low—ultimately keeping rates low, stable, and predictable.[6]

In this rate case, CMP proposed using forecasting methods instead of the traditional historical test year approach for determining a rate case. CMP states that the "backward-looking approach was appropriate when capital investments were more proportional to the ongoing investment level for distribution companies."[7]

CMP provided four reasons for proposing a forward-looking MRP. The first is that forecasting provides guidance on policy, which allows other parties to propose suggestions and assists with regulatory clarity. The second is that by planning further in advance, funding can be prepared with more certainty. This, in turn, ties into the third advantage: improved credit ratings and capital advantages, which "are intensely focused on cost recovery paths for utilities."[8] Planning can lead to stronger credit ratings and thus greater flexibility in capital markets. These all lead to the fourth advantage, which is to ensure mechanisms for rate stability and to protect customers from volatile rates.[9]

Additionally, CMP proposes four revenue adjustments to its proposed yearly revenue requirements, namely:

- plant additions resulting from expected capital investments;[10]

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[3] Central Maine Power Company. *Notice of Intent to File a General Rate Case.* Docket No. 2022-00152. May 26, 2022.

[4] Ibid.

[5] Central Maine Power Company. *2022 Distribution Rate Case Filing: Policy Panel*. August 11, 2022. P. 18.

[6] Ibid.

[7] Ibid. P. 20.

[8] Ibid. P. 24.

[9] Ibid. P. 23-24.

[10] CMP's rate increase is a result of projected distribution plant additions. The company proposes that rate increases in subsequent years be subject to downward revisions based on actual distribution plant additions in the previous years.

- capital investments outside of CMP's base Capital Investment Plan ("CIP");
- symmetrical inflation reconciliation mechanisms;[11] and
- the variance between assumed and actual tax.[12]

Moreover, CMP also requests capital adjustment mechanisms (or a separate funding mechanism) that would apply to five categories of spending outside of CMP's base CIP. These five spending categories are pole replacements, broadband, electric vehicles ("EVs"), energy storage, and metering system upgrades, as described briefly in Figure 2 below.[13] Of these five categories, EVs and storage are new technologies, and therefore relatively new spending categories for CMP. The Company also requests that these categories be reviewed annually, and that rates be adjusted every year based on the actual plant additions resulting from the initiatives that drive these additions.

Figure 2. CMP's proposed categories for a separate funding mechanism

Category	Description
1) Consolidated Communications, Inc. ("CCI") pole replacements	CMP signed an agreement with CCI in 2019 to replace any and all CCI-owned poles that fail Distribution Line Inspection ("DLI") and need to be replaced
2) Broadband-related pole replacements and upgrades	These are capital investments by CMP as part of Maine's Broadband Initiative
3) EV charger projects	EV charger projects have been designed by CMP to support the Maine Climate Action Plan
4) Energy storage projects	CMP proposes two energy storage-related pilot projects to support state and stakeholder energy goals
5) Upgrades to metering systems	CMP proposes changes to Time of Use ("TOU") periods for TOU customer classes

Source: Central Maine Power Company. *2022 Distribution Rate Case Filing: Capital Investment*. August 11, 2022. P. 12.

Next, CMP suggests continuing with its current tracking of reliability and customer service metrics. It does not propose any new measures to improve or enhance its current performance in these categories, nor does the Company put forth any new metrics that track other performance

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[11] Under symmetrical inflation reconciliation, the revenue requirement for the following year will be adjusted based on an inflation factor calculated off the Gross Domestic Product Chained Price Index from the previous year. The difference between difference between actual and projected values is used to revise the revenue requirement amounts. The Company proposes this mechanism for two reasons. First, it is challenging to estimate inflation for future years of the MRP. Second, this mechanism helps mitigate price fluctuations in goods and services, which, as a result, lowers the burden on both customers and the utility.

[12] Central Maine Power Company. *2022 Distribution Rate Case Filing: Policy Panel*. August 11, 2022. P. 15-19.

[13] Ibid. P. 16.

categories such as safety, efficiency, or customer focus, which are some of the major drivers of its capex.[14]

Lastly, CMP proposes a storm cost recovery mechanism that would allow it to recoup costs resulting from storm damages. CMP noted that in the past, it has had "to absorb an unreasonably large portion of prudently incurred storm costs, which has suppressed the Company's returns and made it difficult for it to achieve its allowed return on equity ('ROE')."[15]

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[14] Central Maine Power Company. *2022 Distribution Rate Case Filing: Capital Investment.* August 11, 2022. P. 46-47.

[15] Central Maine Power Company. *2022 Distribution Rate Case Filing: Policy Panel*. August 11, 2022. P. 16.

5 Multi-year rate plan

The MRP is a type of performance mechanism that has been widely used for many years across many jurisdictions throughout the United States and abroad. In general, MRPs are used to achieve one or more of the following goals, which benefit consumers by lowering bills and providing improved electric services:

- support utility cost control and provide cost containment incentives;
- reduce the frequency of rate filing and administrative burden;
- encourage operating flexibility; and
- incent superior productivity and performance.

5.1 MRP and performance-based regulation

The MRP is a common approach to PBR, designed to strengthen incentives for utility performance. PBR is a regulatory approach to rate regulation that provides a wide range of mechanisms to help weaken the link between a utility's rates and its unit costs as well as to incentivize improved efficiency. Jurisdictions may choose to shift to PBR from the traditional COS or rate-of-return regime for several reasons, such as the lack of incentives under COS that encourage prudent and efficient capital investment and cost-efficiency. Moreover, PBR allows sufficient utility freedom to decide how to best optimize its resources given the targets and objectives set by the regulator. In this section, we discuss both the advantages of PBR over COS and the different flavors of PBR, which include MRP. Section 9 (Appendix A) provides more information about PBR.

PBR is best conceptualized as a continuum, ranging from "light" to "comprehensive" mechanisms, rather than a single type of regulatory regime (see Figure 3).

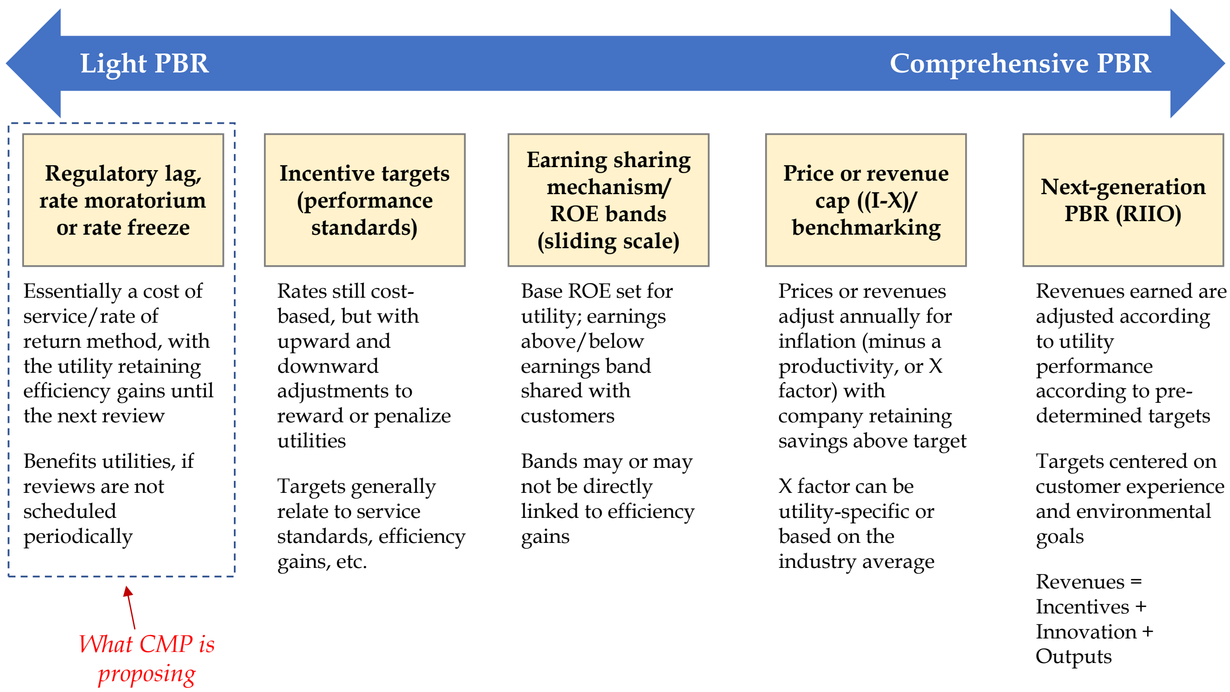
Light PBR includes regulatory lag, moratorium, or rate freezes—this is essentially a COS regulatory approach. Utilities benefit from these mechanisms as they retain any efficiency gains until the next rate review. CMP's proposal can be considered a lighter form of PBR; while it is a multi-rate year plan, it does not include other, stronger incentive mechanisms found in more comprehensive PBR frameworks.

Medium PBR includes mechanisms—such as PIMs and earnings sharing mechanisms ("ESMs")—where payments to a utility are adjusted based on its level of performance. The "medium-comprehensive" form of PBR includes the implementation of a rate cap, where either price or revenue is capped for the regulatory term. This helps promote efficiency, as the mechanism tends to weaken the link between a utility's rates and costs. In turn, it motivates the utility to spend its resources more prudently.

At the end of the continuum is comprehensive PBR, which is focused on outcomes of rather than inputs to the revenue requirement.

The most effective form of PBR depends on the needs and values of the jurisdiction. Each PBR element (or collection of elements) may be appropriate for implementation depending on the circumstances. Generally, the choice of a light versus comprehensive PBR regime is determined by the risk appetite of the utility and the regulator, the range of incentives that the regulator is willing to approve, and the demands of and feedback from interveners.

Figure 3. PBR as a continuum



Aside from these key PBR mechanisms, there are also other components of PBR, such as the length of the multi-year rate plan, productivity factor, treatment of unforeseen events or exogenous factors, off-ramp option, and flow-through factors, discussed in more detail in Section 5.2.

5.2 Key features of an MRP

MRPs tend to exhibit the following core characteristics:

- they introduce a moratorium on general rate cases for three, five, or even up to eight years; and

- they include an ARM, which allows utility revenues or rate caps to escalate when the utility faces external pressures but does not link revenues to the actual cost growth faced by the utility. As discussed in detail in Section 5.2.1, rates or revenues eligible for the ARM can either be forecast, indexed, or designed as a forecast-indexed hybrid.

Another key component of the MRP is either planning for a rate filing for around the final year of the MRP period, or for mid-term reviews during the MRP term. Additional key characteristics of the MRP include:

- trackers, rate riders, and/or deferrals to account for costs not addressed under attrition. Tracker costs that are scheduled in advance are known as Y factors, which encompass the costs of commodities as well as pension and benefit expenses;
- revenue adjustments, such as Z factors, that allow the utility to recover costs stemming from events or developments outside of their control. These may include major storms or adjustments to accounting standards, tax policies, and regulations; and
- PIMs linking the utility's revenues to its performance.

CMP's proposal has a few, but not all, of these MRP features. As discussed earlier, CMP proposed a three-year MRP where the base rate is derived from capex and opex forecasting, and capital adjustments mechanisms will be reviewed and recovered outside of the base rate.

5.2.1 Attrition relief mechanism

Under an MRP, utilities do not file requests for rate changes during the regulatory term. However, the utility's costs do not remain the same throughout the regulatory term. In this regard, attrition relief schemes serve as a mechanism to recoup unrecovered costs. Depending on the ARM used, rates could change during the regulatory term either based on (i) an approved formula (or indexing), (ii) forecasted revenues requirements, or (iii) a hybrid of these two approaches. CMP's proposed MRP applies the forecasted revenue requirements approach.

The MRP provides for cost containment through the use of rate caps, which can either be a price cap or a revenue cap. These are discussed in detail below.

5.2.1.1 ARM approaches

There are three approaches to increasing rates or revenues under the ARM: the use of an indexing formula, forecasting, and a hybrid approach.

Indexing formula

Indexing refers to the process of setting prices based on historical productivity trends, which are usually derived from a statistical analysis of a group of comparable or peer firms. The price the utilities can charge is fixed in advance for a certain period, and may increase by no more than a percent that is inflation less the productivity factor (called the X factor).

The inflation factor adjusts the utility's revenues or rates annually to reflect expected input cost changes. The X factor reflects the potential for productivity gains by the regulated utility or sector and how the regulated utility or sector will perform (in terms of productivity) compared to the rest of the economy. It is set to allow a fair rate of return on capital when the efficient level of costs is achieved. The X factor can either be applied to total costs (capital and operating, maintenance, and administration expenses ("OM&A")) or a subpart of total costs. There are multiple methodologies that can be used to develop the X factor; the method ultimately chosen depends on the regulator's objective, data availability, and data quality.

Under an indexing formula, regulatory burden is lower due to fewer rate filings. The ratemaking process (where deliberations focus on the X factor) is also shorter compared to rate cases in which cost forecasts are reviewed. Examples of markets that have used an indexing formula are Alberta, British Columbia (specifically the utility FortisBC), Hawaii, Massachusetts, and Ontario.

Cost forecasting (or building blocks approach)

As the name implies, under the forecasted revenue requirements approach (also known as the "building blocks" approach), a forecast of total costs is prepared (e.g., operating expenses, return on investment, depreciation expenses, taxes, etc.) for each year of the regulatory term. The forecast should consider productivity improvements and targets necessary capital investment. After this process, these total costs—consisting of expected capital and operating costs and return on asset base—are added together (or "built up") to an allowed revenue requirement for the utility. CMP uses this approach to develop its revenue requirements for the proposed MRP.

Australia, the UK, and several other countries implement this approach. For these markets that are under PBR, the revenue requirement that is forecasted for each year of the regulatory term includes projections of efficient operating and capital expenditure. In setting the allowed revenue amounts, a utility must demonstrate how productivity improvements have been incorporated, such as by benchmarking projected costs against a utility's historical costs and/or other firms in the industry.

When building up the investment component of the cost forecast, utilities generally commission independent engineers. In the UK, the approach is to look at historical and peer benchmarking as well as industry productivity. In reviewing utility business plans, the Office of Gas and Electricity Markets ("Ofgem"), the regulator, hires an expert firm to assess each utility's proposed expenditures that make up the forecast revenue requirement. Where there are concerns about the past performance of a particular utility, Ofgem can choose to take a more intensive review of that particular firm. Alternatively, UK utilities can be fast-tracked through the regulatory process if they have good historical performance. This allows Ofgem to focus resources in areas of need.

Hybrid approach

Under a hybrid approach, both indexing and forecasts are used. For example, the X factor of the indexing approach may only be applied to OM&A, while capex is forecasted and will continue to be recovered on a COS basis. FortisBC in British Columbia is an example of a utility that has utilized this approach. The advantage of this approach is that it provides certainty for capital recovery, which means better financing costs for the utilities. However, regulatory intervention is likely necessary for this method to succeed, notably in ensuring prudence and preventing over-investment. In addition, it may skew incentives for the utility to favor capex solutions.

5.2.1.2 Rate caps

As mentioned earlier, MRP provides for cost containment through the use of rate caps. There are two types of rate caps: price caps and revenue caps. The critical difference between price and revenue cap regimes is related to what the PBR formula applies to—rates in the case of price cap regimes, and revenue requirement in the case of revenue cap regimes. Figure 4 shows the advantages and disadvantages of each rate cap and how they are generally applied.

Figure 4. Price cap vs. revenue cap

	Price Cap	Revenue Cap
What is it?	**Price or average rate** is capped	Utility's **revenue** is capped
Where is it applied?	Applied to either the utility's average price, the average price for each customer class, or to each rate element of each rate schedule	Applied to either revenues from all regulated products or may only apply to revenues used to cover specific costs (like a partial revenue cap of O&M costs)
Advantages	▶ With price caps, regulators **do not need detailed information** about the utility's cost functions to calibrate price cap parameters ▶ Provides incentives for utilities to **meet and expand demand**	▶ More compatible with utilities that face **substantial demand response management programs** or **energy efficiency reductions** in consumer demand ▶ Provides more **pricing flexibility** and is preferable when **costs do not vary significantly with sales volume**
Disadvantages	▶ Pricing **inflexibility**	▶ Requires **accurate forecasts** of revenue requirements

5.2.2 Performance incentives mechanisms

PIMs are important complements to the MRP to ensure that any cost reductions implemented by the utility will not cause a deterioration in service quality. PIMs reward utilities for successfully implementing programs (for example, on demand side management), penalize utilities for failing to meet performance targets (such as reliability targets), or simply track performance metrics for informational purposes. Sometimes, the utility's performance scores are simply tabulated in the form of so-called scorecards and then made publicly available. Section 9.2.2 provides a more detailed discussion on the different types of performance metrics.

In its filings, CMP proposes investments that are "necessary for CMP to meet customer expectations, maintain and enhance the reliability and resiliency of our system, and align with Maine's climate and energy policies and goals."[16] CMP also states that the major drivers of capex include safety, reliability, asset condition, customer focus, and strategic and efficiency.[17] For instance, under customer focus, capex would be used to maintain or improve customer

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[16] Central Maine Power. 2022 *Distribution Rate Case Filing: Policy Panel.* August 11, 2022. P. 9.

[17] Central Maine Power. 2022 *Distribution Rate Case Filing: Capital Investment.* August 11, 2022. P. 46-47.

experience and satisfaction.[18] The Company may in the future choose to consider complementary performance outcomes or metrics that would help identify improvements in these proposed areas.

5.2.3 Trackers and riders

A tracker (or cost tracker) is a type of revenue adjustment or accounting mechanism where a predefined cost recovery level is included in the revenue requirement. The purpose of this mechanism is to allow utilities to quickly recover prudently incurred costs that are not within the utility's control and cannot be added to the rate base ahead of time, such as the cost of fuel, outages caused by extreme weather, pensions, healthcare, and compliance with new policy (i.e., the introduction of a new tax regime) and regulations. Though trackers were traditionally introduced to account for large, volatile costs (such as construction costs), in the context of the MRP they tend to account for costs that are insufficiently addressed by attrition relief. As discussed earlier, CMP is proposing some capital adjustment mechanisms that would be recovered in separate annual rate cases. Capital trackers are discussed in Section 6 along with some examples from other jurisdictions in Section 9.2.3.

5.2.4 Exogenous factor (Z factor)

The exogenous factor, or Z factor, is a mechanism that allows for adjustment in case of the occurance of events that are perceived as beyond the reasonable control of utility management, were neither foreseen nor foreseeable at the time a formula was set, and have a significant impact on company finances. Standards and criteria for the Z factor are discussed and outlined before the start of the regulatory period. These standards and criteria are expected to guide decision-making after the occurrence of any incident. Section 9.2.4 discusses situations in which the Z factor is applied as well as examples of Z factors.

5.2.5 Other potential mechanisms under the MRP

The structure and design of MRPs vary across states; there is no one uniform or universal MRP framework applied across jurisdictions. In addition to common traits, MRPs may contain additional mechanisms, including but not limited to revenue decoupling or lost revenue adjustment mechanisms (which decouple revenues from demand), ESM (where revenue surpluses and deficits are shared with customers), off-ramp mechanisms (which allow for deviation from the MRP in the event of pre-specified outcomes, like extreme return on equity ("ROE")), and other PIMs.[19]

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[18] Ibid.

[19] Lowry, Mark Newton, Scott Brockett, and Matthew Makos. *PBR Rules for North Carolina Electric Utilities*. Docket No. E-100, Sub 178. Exhibit A. Prepared by Pacific Economics Group Research LLC. December 17, 2021. P. 18, 33-34, 37-38.

ESMs[20] are designed so that—if formula-driven price adjustments result in too wide a divergence between prices and costs—the extraordinary earnings (or losses) are shared between the company and its customers rather than retained (or absorbed) entirely by the company.[21] Figure 5 provides examples of jurisdictions that have ESM provisions. Currently, CMP does not propose any ESM in its rate filing. Section 9.2.5 discusses the components and examples of ESM.

Figure 5. Select jurisdictions and their ESM provisions

State	Utility	Term	Approved Return on Equity	Deadband	Asymmetric/ symmetric	Sharing split Ratepayer/ utility	Notes	Source
Hawaii	Hawaii Electric	2022-2027	9.5%	6.5%-12.5% 300 bp	Asymmetric	<6.5% - 50/50 >12.5% - 50/50 >14% - 90/10		Decision and Order No. 37507. Docket No. 2018-0088
New Hampshire	Northern Utilities	2016-2020	9.5%	9.5%-10.5% 100 BP	Asymmetric	>10.5% - 50/50	Process of changing collar to 11%	DE 16-384. Order No. 26,007
Connecticut	Connecticut Light and Power Company	2018-2021	9.25%	n/a	Asymmetric	>9.25% - 50/50	ESM will continue until next rate case	Docket NO. 17-10-46
New York	Central Hudson Gas & Electric	2021-2024	9%	9%-9.5% 50 bp	Asymmetric	>9.5% - 50/50 >10% - 75/25 >10.5 – 90/10		Case 20-E-0428 & Case 20-G-0429
Vermont	Green Mountain Power Corporation	2019-2022	9.06% (2019) 8.20% (2020) 8.57% (2021)	+/-50 bp	Asymmetric	>50bp – 75/25 >125bp – 100/0 <50bp – 50/50 <150bp – 100/0	ESM under review in ongoing rate case	Case No. 20-1401-PET
Massachusetts	Eversource Energy	2021-2026	9.9%	+100 bp -150 bp	Asymmetric	>100bp 75/25 <150 bp – 50/50 <200 bp – 75-25		D.P.U. 19-120

PBR plans typically include or prescribe mechanisms for modifications or even termination. A re-opener provides opportunities for the revision or modification of a particular component of the PBR plan before the end of the regulatory period. In contrast, an off-ramp allows for the review and possible termination of the entire PBR plan. These two mechanisms safeguard the utilities and customers against unexpected outcomes in implementing a PBR plan. Circumstances that may trigger a re-opener or off-ramp are defined before PBR implementation and are usually events that are out of management's control. However, unlike the events covered under the Z factor, utilities must present solid justification for the review or the termination of the PBR plan and demonstrate that the ratemaking regime in place is unsustainable and will likely cause a

[20] The ESM can either be a stand-alone regulatory mechanism or part of an MRP.

[21] This mechanism serves the same basic purpose as the clawback mechanism within a traditional COS system: to ensure that prices do not get too distorted or deviate too much from actual costs. In the context of an indexation formula, an alternative to the ESM is an exit ramp, which triggers an automatic end to the current formula application period (and thereby initiates a COS rate review) if prices deviate too much from costs.

material impact on either the firm or its customers. Figure 6 shows examples of events that can qualify for off-ramps.

An example of a utility that initiated an off-ramp request is ENMAX in Alberta. On October 15, 2012, ENMAX applied to reopen the transmission component of its PBR plan because its 2011 and 2012 ROE had fallen below the re-opener threshold level. ENMAX requested approval of remedial adjustments to the capital growth factor ("G factor") and X factor components of its PBR plan. In November 2013, the Alberta Utilities Commission ("AUC") approved the request for a re-opener to determine whether the reported ROEs were evidence of an issue with the structure of the PBR plan that must be remedied by the regulator.[22]

Figure 6. Examples of events that may qualify for off-ramps

Jurisdiction	Sector	Re-opener or off-ramp triggers
Alberta	Distribution	***ROE-*** If utility earned ROE that is 500 basis points above or below the approved ROE for one year or 300 basis points for two consecutive years *Change in service area* - material contraction and expansion of customers or service territories *Substantial change in circumstances* - material event that is completely unforeseen and cannot be accommodated within the parameters of the PBR plan
California	Distribution	***ROE*** – An ROE of 300 basis points above authorized earnings for at least two consecutive years and an ROE of 175 basis points below approved earnings for two consecutive years make the PBR subject to a motion for voluntary suspension
Ontario	Distribution	***ROE*** – If utility earned ROE that is 300 basis points above or below the approved ROE for one year
UK	Distribution	***Above the capex allowance***– if total spending on a high-value project is 20% over the total ex-ante allowance, and all outputs are met, this project will be eligible for a reopener.

Sources: Alberta Utilities Commission, California Public Utilities Commission, Ofgem, Ontario Energy Board

[22] Alberta Utilities Commission. *ENMAX Power Corporation 2012 Formula-Based Ratemaking Transmission Tariff Reopener Determination*. Decision 2013-399. November 4, 2013. P. 5.

6 Capital trackers

An MRP regime cannot accommodate all the lumpy and capital-intensive projects that are common in the utility industry. To address this limitation, capital trackers are often used. Capital trackers allow the utility to recover unanticipated or unusual investment costs between rate cases, or certain types or categories of capital expenditure approved by the regulator. A capital tracker, therefore, is an explicit mechanism that is used to track and recover certain capex. A utility may prefer the capital tracker approach because it provides certainty that capital costs will be recovered and, as a result, reduces the utility's financing costs. However, the use of a capital tracker may require the active participation of and entail a high administrative burden on the part of the regulator, utility, and stakeholders during the rate planning stage.

6.1.1 How does it work?

Capex projects eligible for capital tracker status (i.e., treated outside the indexing rate formula or base rate forecasts) usually either meet a certain dollar threshold or other specified criteria. These criteria are generally narrow or otherwise well-defined in a regulatory process outside an MRP (or PBR) proceeding. This is to ensure that the incentive properties of the MRP (or PBR framework) are maintained. Special tracker accounts are created to hold funds that either adjust the utility's revenue requirement once actual versus forecast revenues or operating costs have been trued up, or smooth the recovery of volatile costs.

Each regulator will usually initiate its own proceeding to establish the definition and parameters for capital trackers, which has led to unique capital tracker criteria across jurisdictions. This means that the capex eligible for capital tracker treatment—or simply, an explanation of how capital trackers work—varies from one regulated utility to the next. For example, in Alberta, capital projects eligible for capital tracker treatment cannot have been previously included in the distribution utility's rate base and must have been required by a third party. In Ontario, in addition to setting a $10 million threshold for individual projects, the eligible project must be discrete, incremental, and excluded from annual capital programs. In Massachusetts, capital trackers are applicable to projects that were pre-authorized by the regulator, incremental to costs authorized in base rates, and deemed to have been prudently incurred. These cases are examined in further detail in the subsections that follow.

6.1.2 Alberta's capital tracker criteria

Alberta is under a PBR regime, where distribution rates are adjusted each year through an I-X mechanism plus other specific adjustments, including:

- **Z factor** - a factor that accounts for the effects of exogenous and material events for which the utility has no other reasonable cost recovery or refund mechanism within the PBR plan;
- **K factor** - an adjustment to supplement capital funding outside of the funding generated under the I-X mechanism; and

- **Y factor** - an adjustment for certain flow-through costs that are recovered from or refunded directly to customers.

During its first PBR term (2013-2017),[23] the Alberta regulator included the capital tracker mechanism to address the utilities' concern that the I-X mechanism by itself would provide insufficient revenues to fund necessary capex related to accelerated system modernization projects, externally driven projects, and capex required for a rapidly expanding system. In Decision 2012-237, the AUC provided guidelines for the establishment of capital trackers. According to the AUC, the capital tracker mechanism was "intended to provide distribution utilities with a reasonable opportunity to recover their prudently incurred capital costs, including a fair return, and to recognize the unique circumstances of each regulated distribution utility."[24]

For a capital project to receive consideration as a capital tracker, the utilities in Alberta must demonstrate that all three criteria listed in Figure 7 have been satisfied. Limiting trackers by setting specific criteria is beneficial because it maintains the incentives established under the PBR framework while acknowledging that utilities require a mechanism to deal with lumpy investments.[25] In addition, according to the AUC, a structured criteria-based approach provides the most objective method for assessing whether projects qualify as capital trackers.

The first criterion, which states that the project must be outside the normal course of ongoing operations, helps avoid the double-counting of capital-related costs that should be funded through either the I-X or capital tracker mechanism, but not both. An accounting test mechanism was established to ensure the absence of double-counting and calculates the amount of investment outside the normal course of the utility's ongoing operations. The accounting test is based on the project net cost approach, where the revenue generated under the I-X mechanism for each capital project (or program) is compared to the forecast revenue requirement associated with the capital project (or program). A K factor adjustment in the PBR formula collects the individual project-by-project revenue shortfalls, the sum of which is approved for capital treatment.[26]

Also, under the first criterion, the utility needs to demonstrate that the project is essential and that its ability to provide the required services would be impacted if the expenditures are not carried out.[27] Hence, to meet this criterion, the utility must also submit an engineering study to

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[23] This was the first PBR term for all utilities except ENMAX, which had already been under PBR since 2009.

[24] Alberta Utilities Commission. *Distribution Performance-Based Regulation Commission Initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications*. April 8, 2015. P. 47.

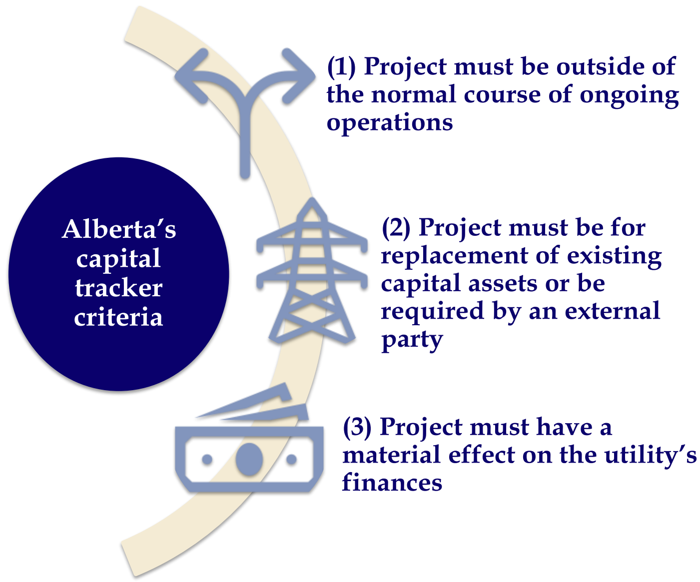
[25] Alberta Utilities Commission. *Rate Regulation Initiative Distribution Performance-Based Regulation*. Decision 2012-237. September 12, 2012. P. 124.

[26] Alberta Utilities Commission. *Distribution Performance-Based Regulation Commission Initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications*. April 8, 2015. P. 10.

[27] Alberta Utilities Commission. *Rate Regulation Initiative; Distribution Performance-Based Regulation*. Decision 2012-237. September 12, 2012. P. 126.

justify the proposed capital expenditures. Furthermore, a utility is also required to provide proof that the proposed capital tracker project could not have been undertaken before as part of a prudent capital maintenance and replacement program.[28]

Figure 7. Alberta's capital tracker criteria



Source: Alberta Utilities Commission. *Rate Regulation Initiative; Distribution Performance-Based Regulation*. Decision 2012-237. September 12, 2012. P. 124-128.

The second criterion, which requires that a project replace existing capital assets or be required by an external party, excludes projects that must accommodate customer or demand growth.[29] This is because as the system grows, it generates new revenue sources that pay for the costs of the new capital. To qualify, the utility must also provide evidence that costs are significantly different from historical trends.

The purpose of the last criterion is to limit the use of capital trackers; projects must have a material impact on the utility's finances due to the administrative and regulatory burden associated with tracker administration.[30]

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[28] Ibid. P. 126.

[29] Ibid. P. 127.

[30] Ibid. P. 128.

When applying for a capital tracker, a utility must submit types of several documents and evidence. These include, but are not limited to, the following:[31]

- the rationale for the project, including the nature, scope, location, timing, and cost of the project;
- evidence demonstrating that, in the absence of the proposed capital expenditures, deterioration in service quality and safety would result;
- evidence that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program;
- a discussion of any reasonable alternatives, including the rationale for recommending the proposed solution;
- the actual and forecast capital additions for all projects and programs in Excel format with linked and working formulas;
- supporting calculations for any component of capital additions or capital-related revenue requirement; and
- proof that the revenue generated under the I-X mechanism for each capital tracker project or program is not covered by the actual or forecast revenue requirement associated with that capital project or program.

Alberta utilities were permitted to apply for capital trackers on a forecast basis. The approved forecasted cost of a capital tracker project was included in rates on an interim basis (i.e., subject to consideration in the next PBR term) and was subject to a true-up of prudently incurred actual expenditures only after the project was completed. The regulator believed that, through its true-up process (which tests the prudence of actual capex), the capital tracker mechanism retains some of PBR's efficiency incentives due to the risk of regulatory disallowances in the future if expenditures are not actually reasonably incurred. Furthermore, the regulator has stated that the true-up mechanism with a prudence review also "mitigates somewhat the incentive for companies to overstate the initial capital tracker forecasts."[32]

During its second PBR term (2018-2022), the regulator decided to divide capital additions into two categories that would be funded using two different mechanisms. Broadly, these were:

- **Type 1 capital, funded through capital trackers:** Type 1 capital is defined as a project that meets two criteria – (i) it "must be of a type that is extraordinary and not previously

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[31] Alberta Utilities Commission. *Distribution Performance-Based Regulation Commission Initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications*. April 8, 2015. P. 11-12, 25-26.

[32] Alberta Utilities Commission. *Distribution Performance-Based Regulation 2013 Capital Tracker Applications*. December 6, 2013. P. 10-11.

included in the distribution utility's rate base," and (ii) it "must be required by a third party."[33] Type 1 capital is funded through capital trackers, like the approach taken under the first PBR term; and

- **Type 2 capital, funded through a K-bar methodology:** all other capital is defined as Type 2 capital and funded through a formulaic K-bar approach (which is different from K factor). Under this approach, "a base K-bar amount will be established for 2018... which will determine a capital funding shortfall or surplus for each program or project... In subsequent years, an additional amount of incremental K-bar funding is calculated by indexing the 2018 base K-bar amount by I-X."[34] This approach provided distribution facility owners with "a predetermined amount of incremental capital funding for all... of the PBR term" and allowed utilities to "manage their capital programs within the capital funding constraints."[35]

The regulator argued that establishing these two categories of capital would "increase regulatory efficiency by reducing the number of regulatory proceedings to approve and potentially true up capital tacker projects and programs" and "ensure that the vast majority of capital will be subject to the superior incentive properties of PBR."[36]

6.1.3 Ontario's capital trackers criteria

Like Alberta, Ontario is also under a PBR regime. It is unique, however, in that, starting from the fourth generation of PBR, utilities were given three options on how to set rates. The utility chooses the method that best meets its requirements and circumstances: (i) Price Cap incentive regulation ("IR"), (ii) Custom IR, and (iii) Annual IR Index. Figure 8 below shows the different parameters of these three options. This framework calls for utilities to focus on customer requirements and to demonstrate that their investment plans support cost-effective planning and operation of the distribution network.

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[33] Alberta Utilities Commission. *Errata to Decision 20414-D01-2016; 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities.* Proceeding 20414. February 6, 2017. P. 22.

[34] Ibid. P. 63.

[35] Ibid. P. 49.

[36] Ibid. P. 52.

Figure 8. Key elements of the three rate-setting options

<table>
<tr><th>Setting of Rates</th><th>Price Cap IR</th><th>Custom IR</th><th>Annual IR Index</th></tr>
<tr><td>Appropriate for:</td><td>Distributors that anticipate some incremental investment needs will arise during the plan term</td><td>Distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures</td><td>Distributors with relatively steady state investment needs</td></tr>
<tr><td>"Going in" rates</td><td>Determined in a single forward test-year cost of service review</td><td>Determined in a multi-year application review</td><td>No COS review; existing rates adjusted by the Annual Adjustment Mechanism</td></tr>
<tr><td>Coverage</td><td colspan="3">Comprehensive</td></tr>
<tr><td>Annual Adjustment Mechanism: Inflation</td><td>Composite Index</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board based on (1) the distributor's forecast (revenue and costs, inflation, productivity), (2) the inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distribution forecasts</td><td>Composite Index</td></tr>
<tr><td>Annual Adjustment Mechanism: Productivity</td><td>Peer Group X-factors comprised of (1) Industry TFP growth potential and (2) a stretch factor</td><td>Based on Price Cap IR X-factors</td></tr>
<tr><td>Role of Benchmarking</td><td>To address reasonableness of distributor cost forecast and to assign stretch factors</td><td>N/A</td></tr>
<tr><td rowspan="2">Sharing of Benefits</td><td colspan="3">Productivity factor</td></tr>
<tr><td>Stretch factor</td><td>Case-by-base</td><td>Highest Price Cap IR stretch factor</td></tr>
<tr><td>Term</td><td>5 years (rebasing plus 4 years)</td><td>Minimum term of 5 years</td><td>No fixed term</td></tr>
<tr><td>Incremental Capital Module</td><td>On application</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Z factor</td><td colspan="3">Must satisfy the three eligibility criteria set by the Board, namely: (i) causation, (ii) materiality, and (iii) prudence</td></tr>
<tr><td>Performance Reporting and Monitoring</td><td colspan="3">A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels</td></tr>
</table>

Source: Ontario Energy Board. *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.* October 2012. P.13.

Under the **Price Cap IR**, which already existed under the third generation of PBR, rates are set on a single forward-test year COS basis, and subsequent rates are based on a price cap index formula. The term is longer (five years, which includes rebasing plus four years) to "better align rate-setting and distributor planning, strengthen efficiency incentives, support innovation, and help manage the pace of rate increases for customers."[37]

Under **Custom IR**, rates are based on a five-year forecast of a distributor's revenue requirements and sales volumes. This method is intended to be customized to fit the utility's specific circumstances, but expected productivity gains would be explicitly included in the rate adjustment mechanism. Utilities that opt for Custom IR need to submit robust evidence of cost

[37] Ontario Energy Board. *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.* October 2012. P. 15.

and revenue forecasts and detailed infrastructure investment plans for the term of the plan. Utilities are also required to submit yearly reports of their capital spending.

The third option, the **Annual IR Index**, is simpler than the other two options. A price cap index formula adjusts rates, so rates are adjusted yearly by the growth of the I factor minus an X factor. All utilities under this option have the same X factor. Utilities under the Annual IR Index must file a Distribution System Plan ("DSP") within five years of their last approved cost of service decision and are required to do so in five-year intervals thereafter.[38]

Of these three rate-setting options under PBR, only Price Cap IR includes the concept of the capital tracker, which Ontario calls the Incremental Capital Module ("ICM"). Under Custom IR, there is no ICM as distributors are expected to operate under their Board-approved multi-year rates. Similar to Custom IR, Annual IR Index also does not implement the ICM as it is assumed that the utilities are under a "steady state" of operation.[39]

Ontario introduced the ICM mechanism during the province's third generation of PBR in 2011 to address concerns that necessary capital investment (for example, capex necessary to replace and refresh aging electricity distribution infrastructure in Ontario or meet new policy mandates) would otherwise remain unfunded under the base incentive rate mechanism ("IRM").[40] The ICM allows distributors to request rate relief for non-routine capital investments that are not included in their approved capital plans for the following year and/or are not funded through existing rates.[41] The ICM calculates an amount to add to rates above and beyond the basic PBR mechanism. It functions similarly to a capital tracker, which provides cost recovery for certain capex. Utilities applying for rate relief under the ICM need to meet three criteria: materiality, need, and prudence, which are described below.

Rate relief for incremental capex only applies if expenditure is above a materiality threshold.[42] If the changes are immaterial (i.e., below a certain threshold), then the additional capex is accommodated through rebasing at the end of the rate period rather than through rate relief during the PBR period. Figure 9 presents the methodology defined by the Ontario Energy Board ("OEB," or the Ontario regulator) to calculate the materiality threshold.

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[38] Ontario Energy Board. *Handbook for Utility Rate Applications.* October 13, 2016.

[39] Under a "steady state," it is assumed that the pace at which the utility makes investments is aligned with both the capital it has already built as well as the depreciation of that capital. In other words, under a steady state, the replenishment of capital is meant to offset the reduction in capital assets resulting from their usage and physical deterioration.

[40] Ontario's terminology for PBR is "incentive rate mechanisms," or IRM.

[41] Ontario Energy Board. *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*. September 17, 2008.

[42] A utility applying for ICM would calculate the eligible incremental capital amount by taking the difference between the current year's total non-discretionary capex and the materiality threshold.

The so-called need criterion confirms that the capital funded through the ICM is non-discretionary. This criterion in ICM application was also meant to ensure that there is no double-counting and that the funding is not otherwise available under the base IRM mechanism.

The OEB acknowledged that the inclusion of the ICM in the PBR scheme likely reduces the incentive for utilities to manage their capex. Thus, utilities that receive rate relief through the ICM must report to the regulator on annual actual capital spending after the granting of rate relief. In addition, a prudence review is carried out by the regulator at the end of the rate period to determine the amount of the additional capex to be included in the rate base for these utilities going forward. A comparison of projected and actual capital investment (including over-spending or under-spending) is also reviewed at rebasing.

Figure 9. Method for calculating materiality threshold

$$\textit{Threshold Value} = 1 + (RB/d)*(g+PCI*(1+g))+20\%$$

Where:

- RB = rate base included in base rates ($);
- d = depreciation expense included in base rates ($);
- g = revenue change from load growth (%); and
- PCI = price cap index (% inflation less productivity factor less stretch factor)

The values for "RB" and "d" are the Board-approved amounts in the utility's base year rate decision

Source: Ontario Energy Board. *Filing Requirements for Transmission and Distribution Applications*. June 22, 2011.

Building on the foundation of the ICM, the Advanced Capital Module ("ACM") was introduced in 2014 to improve the regulatory efficiency of the review and approval of proposed incremental capital expenditures. An ACM proposal is made during the COS application to identify, based on the five-year capital plan in the Distribution System Plan, qualifying incremental capital expenditures during the subsequent IRM period that are necessary but require funding beyond what is sustained by IRM-adjusted rates and customer and load growth.[43]

To be eligible for the ICM or ACM, capital spending must respect certain criteria listed in Figure 10. These criteria include meeting a capex-to-depreciation materiality threshold between 170-190%. The threshold-set formula takes into account the rate base, depreciation expense, price cap index, and the percentage difference in distribution revenues between the most recent complete year and the approved base year.

[43] Ontario Energy Board. *Handbook for Utility Rate Applications.* October 13, 2016.

The criteria have also evolved since the ACM's introduction. With respect to materiality, eligibility was constrained to project expenditures over and above the regulator-defined threshold calculation that was expected to be absorbed within the total capital budget. In terms of need, the OEB introduced a means test that disqualified distributors whose regulated return exceeds 300 basis points above the ROE embedded in their rates and removed the non-discretionary requirement. The prudence criterion remained unchanged.[44] Figure 10 shows the updated criteria under the ICM/ACM eligibility.

Figure 10. Criteria for ICM/ACM eligibility

Criteria	3GIRM description	2014 revised description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distribution; otherwise they should be dealt with at rebasing.	A capital budget will be deemed to be material if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which the rates were derived.	The distribution must pass a new means test. Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily the least initial cost) for ratepayers.	

Note: "3GIRM" stands for third generation incentive ratemaking regulation.

Source: Ontario Energy Board. *3rd Generation Incentive Regulation for Ontario's Electricity Distributors*. July 14, 2008. P.25.

6.1.4 Massachusetts' grid modernization capital tracker

There are several capital trackers in Massachusetts, of which one is for the state's Grid Modernization Plan ("GMP"). In 2012, the Massachusetts Department of Public Utilities ("DPU")

[44] Ontario Energy Board. *New Policy Options for the Funding of Capital Investments: Supplemental Report*. January 22, 2016.

began an investigation "into the modernization of the electric grid"[45] and approved grid modernization plans for each utility in the state.[46] The DPU writes in Order 12-76-B that, "grid modernization will empower customers to manage their use of electricity better and save money, and enhance the reliability of electricity service in the face of increasingly extreme weather."[47] The DPU set four broad objectives for each distribution company to make "measurable progress."[48] These objectives are: "(i) reducing the effects of outages; (ii) optimizing demand, which includes reducing system and customer costs; (iii) integrating distributed resources; and (iv) improving workforce and asset management."[49]

Figure 11: Grid Modernization Plan objectives

Objective	Description
1) Reducing the effects of outages	Improving reliability for customers in line with the DPU's goals and reducing the number and duration of outages due to weather while enhancing resiliency
2) Optimizing demand	Reducing system and customer costs to ensure the system is built to meet peak electricity demand
3) Integrating distributed resources	Ensuring smooth integration of renewables, electric vehicles, microgrids, and storage into the grid to meet climate and resiliency goals
4) Improving workforce and asset management	Improve management and efficiency of workforces

Source: Commonwealth of Massachusetts: Department of Public Utilities. *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid.* Docket No. 12-76-B. Web. June 12, 2014. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9235208>. P. 10-13.

These plans include pre-authorized investment categories, such as distribution automation, volt optimization, and advanced communications infrastructure.[50] Capital investments into these categories are tracked in each utility's annual grid modernization report, including performance metrics that track the benefits of these investments.[51] In Order 12-76-A, the DPU concluded that

[45] Commonwealth of Massachusetts: Department of Public Utilities. *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid.* Docket No. 12-76-A. Web. December 2013. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9241637>. P. 1.

[46] "Grid modernization." Mass.gov. Web. Accessed October 1, 2022. <https://www.mass.gov/info-details/grid-modernization>.

[47] Commonwealth of Massachusetts: Department of Public Utilities. *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid.* Docket No. 12-76-B. Web. June 12, 2014. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9235208>. P. 7-8.

[48] Ibid. P. 9.

[49] Ibid.

[50] Ibid.

[51] Ibid.

grid modernization should be a part of normal business practices and that it will evaluate these investments in base distribution rate cases at the same standard as other capital investments.[52] For example, in National Grid's most recent rate case, the DPU denied the utility's proposal to recover the revenue requirement of energy storage systems installations through the grid modernization recovery provision because National Grid did not bring forward sufficient information to justify the reasonableness of the proposal.[53] However, the DPU later notes that National Grid can file a proposal with its updated GMP or submit a project proposal at a later date.[54]

To recover investments under the GMP, the DPU approved a short-term targeted cost recovery mechanism—the Grid Modernization Factor ("GMF")—for pre-authorized grid modernization investments.[55] Recovery through the GMF is permissible if costs are "reasonable, prudently incurred, incremental, and otherwise eligible for recovery."[56] This cost recovery mechanism varies by utility and includes the following costs and investments:

1. both capital and operations and maintenance ("O&M") costs;
2. incremental grid modernization costs that are prudently incurred, in service, and used and useful to customers; and
3. applies to investments made during the first two GMPs only.[57]

As per Order 21-80/81/82-A, each utility was required to submit revisions to their respective tariffs. These revisions were triggered by the DPU approving "a protocol for tracking and identifying incremental grid modernization O&M expense, a five-step test to determine whether O&M labor expense is eligible for recovery through the GMF, and an incremental overhead and burdens test to determine whether non-capitalized overhead and burdens O&M expense is eligible for recovery through GMF."[58]

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[52] Commonwealth of Massachusetts: Department of Public Utilities. *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid.* Docket No. 12-76-A. Web. December 23, 2013. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9241637>. P. 18.

[53] Commonwealth of Massachusetts: Department of Public Utilities. *Petition of Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, pursuant to G.L. c. 164, section 94 and 220 CMR 5.00, for Approval of General Increases in Base Distribution Rates for Electric Service*. Docket No. 18-150. Web. September 2019. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11262053>. P. 133.

[54] Ibid. P. 334.

[55] Ibid. P. 2.

[56] Ibid. P. 5-6.

[57] Ibid.

[58] Ibid. P. 110.

Massachusetts utilities must submit annual reports that cover their performance under their respective plans from the prior year and a grid modernization cost recovery filing with the proposed GMFs.[59] Figure 12 shows what data the utilities share with the DPU's consultant Guidehouse, which uses this information to evaluate each utility's GMP.[60] The results of this analysis are then submitted to the DPU.[61] According to DPU 15-120/121/122, the purpose of metrics is to record and report the utilities' performance. Currently, the metrics are not tied to any incentives or penalties.[62]

Next, the DPU reviews each utility's plan—which includes a prudence review of investments at the conclusion of the investment term—and has Guidehouse assess the utilities' yearly spending.[63]

Specifically, Guidehouse analyzes the five pre-authorized investment categories by examining the amount spent, the technologies deployed, and the impacts on outages and reliability.[64] As an example, Guidehouse concluded that, between 2018 and 2021, Eversource and National Grid invested approximately $69.4 million in Advanced Distribution Automation ("ADA") technology.[65] ADA investments were specifically made in the categories of "New Overhead Recloser Locations, New Overhead Recloser Locations with Ties, and Feeder Monitors."[66] In its assessment of investment prudency, Guidehouse concluded that "Eversource ADA spending is tracking closely (99%) to plan (as filed in Eversource 2020 Annual Report). Actual spending from 2018-2021 ($60.9 million) also came close to DPU pre-authorized budget of $58 million."[67]

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59 Commonwealth of Massachusetts: Department of Public Utilities. *Memorandum RE: Grid Modernization Term Report Format.* Docket No. 21-116. Web. February 15, 2022. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14509628>. P. 2.

60 Commonwealth of Massachusetts: Department of Public Utilities. *Massachusetts Grid Modernization Program Year 2021 Evaluation Report: Advanced Distribution Automation (ADA).* Docket No. 15-120/15-121/15-122. Web. July 1, 2022. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15168394>. P. iv.

61 Ibid.

62 Commonwealth of Massachusetts: Department of Public Utilities. *Grid Modernization Order*. Docket No. 15-120/15-121/15-122. Web. May 10, 2018. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163509>. P. 197.

63 Ibid; "Grid modernization." Mass.gov. Web. Accessed October 1, 2022. <https://www.mass.gov/info-details/grid-modernization>.

64 Commonwealth of Massachusetts: Department of Public Utilities. *Massachusetts Grid Modernization Program Year 2021 Evaluation Report: Advanced Distribution Automation (ADA).* Docket No. 15-120/15-121/15-122. Web. July 1, 2022. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15168394>. P. iv.

65 Ibid. P. 7.

66 Ibid. P. 8.

67 Ibid. P. 21.

Figure 12. Advanced Distribution Automation ("ADA") evaluation metrics

Metric Type	ADA Evaluation Metrics	ES (Eversource)	NG (National Grid)
IM	System Automation Saturation	✓	✓
IM	Number of Devices or Other Technologies Deployed	✓	✓
IM	Cost for Deployment	✓	✓
IM	Deviation between Actual and Planned Deployment for the Plan Year	✓	✓
IM	Projected Deployment for the Reminder of the 3-Year Term	✓	✓
PM	Numbers of Customers that Benefit from GMP-Funded Distribution Automation Devices	✓	✓
PM	Grid Modernization Investments' Effect on Outage Durations	✓	✓
PM	Grid Modernization Investments' Effect on Outage Frequency	✓	✓
PM	Eversource Customer Outage Metric	✓	
PM	National Grid Specific Metric: Impact of ADA Investments on Customer Minutes of Interruption (CMI) for Main-Line Interruptions		✓
Other	Case Studies	✓	✓

Note: IM means Infrastructure Metric, and PM means Performance Metric.

Source: Commonwealth of Massachusetts: Department of Public Utilities. *Massachusetts Grid Modernization Program Year 2021 Evaluation Report: Advanced Distribution Automation (ADA).* Docket No. 15-120/15-121/15-122. Web. July 1, 2022. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15168394>. P. iv.

The evaluation report concluded that Eversource did exceed costs in some categories but overall did track closely with its original investment plan. The evaluation review is still ongoing, with the Massachusetts Department of Energy Resources filing a petition for leave to intervene on October 18, 2022.[68]

[68] Commonwealth of Massachusetts: Department of Public Utilities. *Massachusetts Department of Energy Resources' Petition for Leave to Intervene.* Docket No. 22-41. Web. October 18, 2022. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15650026>. P. 2.

7 Examples of mechanisms that help to ensure the accuracy of forecasts under the MRP

This section covers how regulators may opt to reconcile forecasted costs with actual expenditures, and other ways to ensure that a utility's expenditure was prudent, used and useful, and up to performance expectations. In many North American jurisdictions, regulators will put in place a review process for forecast and/or actual utility spending that happens not yearly but at the end of a rate period or once actual costs significantly deviate from forecasted costs. These less frequent reviews are made possible by PBR mechanisms, earnings reconciliation, revenue adjustment formulas, or other regulatory tools that are flexible enough to accommodate changes in capital expenditures without completely eliminating the utility's incentive for cost control. Here, the regulator ensures a prudent level of spending while at the same time provides flexibility to the utility to prioritize capital projects. Some international jurisdictions take these mechanisms further by tying utility revenues to performance. Examples of these mechanisms are provided in the subsections that follow.

7.1 Ex-ante and ex-post reviews of spending

Prudency reviews are time and resource intensive for the regulator, but a necessary check on the utility and the system improvements and other benefits promised to ratepayers. LEI is not aware of any mechanism implemented in any jurisdiction to automate or replace a full prudency review; however, some PBR mechanisms can be put in place to help ensure that the utility is spending capital on necessary, useful, and beneficial projects. There are two general categories of reviews: ex-ante reviews of forecasts, and ex-post prudency reviews of spending. Ultimately, the regulator must perform a thorough ex-ante review of forecasts at some point in the regulatory term to ensure that forecasted spending remains relevant and efficient.

With respect to ex-ante reviews, the design of a PBR framework may help the regulator to identify early on in the regulatory term the extent to which the utility is fulfilling its spending requirements. In other words, the ex-ante design of PBR elements themselves ensure prudent spending. For example, the foundation for base rates is set using historical data, benchmarking to peer utility performance data, or production cost simulations, among other tools. Then, the PBR mechanisms maximize the incentive for cost control (such as through the implementation of revenue caps or ESM) and minimize opportunities for gaming (such as by implementing well-defined metrics). Clear metrics and transparent and verifiable data promote more efficient utility reviews.[69] This all occurs ex-ante—before any money is spent by the utility.

With respect to ex-post reviews, in many jurisdictions, the utility's costs and earnings are reviewed through annual and/or quarterly rate reviews; rate cases; and/or third-party audits, interrogatories, and cross-examination. Alternatively, a regulator may consider conducting audits or evaluating the utility's proposal for reasonableness and prudence before costs become

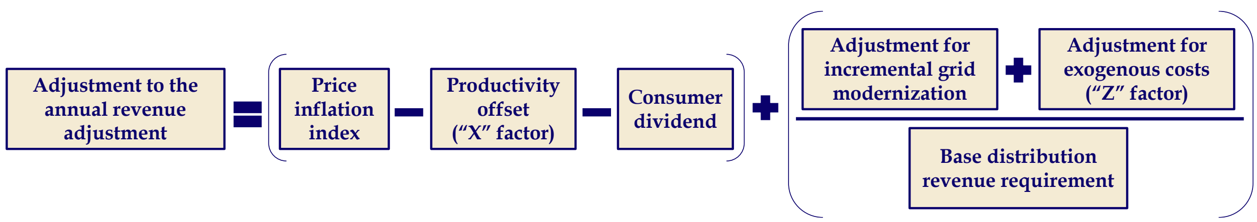
[69] Littell, et al. *Next-Generation Performance-Based Regulation; Emphasizing Utility Performance to Unleash Power Sector Innovation*. Technical Report, NREL/TP-6A50-68512. Web. September 2017. <https://www.nrel.gov/docs/fy17osti/68512.pdf>.

incorporated into rates.[70] Then, as in the case of Ontario, any differences between forecasted and actual spending are either refunded to or recovered from ratepayers, as applicable and as ordered by the regulator. Here, a formal prudency review is not undertaken because a revenue requirement price cap had been approved and established for the duration of the rate period. Only incremental costs are reviewed.[71]

7.1.1 Massachusetts

The electric distribution utilities in Massachusetts are currently under a framework that caps revenue per customer.[72] This revenue decoupling framework starts with the revenue cap per customer, which is established based on a review of the cost of service for a historical test year. The PBR framework then applies a rate adjustment formula to that base revenue per customer year over year. The adjustment is based on a pre-set X factor and an I factor, less a consumer dividend. The X factor and the consumer dividend are fixed for the regulatory term and the inflation factor is adjusted yearly based on the inflation rate from the previous year. This means that the base rate revenues will not rise above the I-X trajectory in the longer term.

Figure 13. Revenue cap formula



Source: Massachusetts Department of Public Utilities

The rate is also adjusted every year by the exogenous costs (Z factor) and adjustment for incremental grid modernization investments that are in total divided by the base distribution revenue requirement. The Z factor accounts for costs that are incurred for reasons that are beyond the utility's control. The Massachusetts revenue cap is supplemented with an ESM, which ensures that earnings above the regulator-approved ROE is returned to ratepayers.[73]

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[70] Costello, Ken. *Future Test Years: Evidence from State Utility Commissions*. National Regulatory Research Institute. Report No. 13-10. Web. October 2013. <https://pubs.naruc.org/pub/FA86C105-05F5-9766-BC78-29829AC50361>.

[71] Ontario Energy Board. *Report of the Board; New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*. EB-2014-0219. September 18, 2014.

[72] In its rate filing last year, NSTAR Electric proposed a price cap mechanism. The proceeding is still ongoing.

[73] Commonwealth of Massachusetts: Department of Public Utilities. *Order Establishing Eversource's Revenue Requirement*. Docket No. 17-05. Web. November 30, 2017. <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9171660>.

Massachusetts's revenue cap per customer and PBR rate-adjustment mechanism creates a strong economic incentive for the utilities to manage their costs. If a utility can reduce its costs more substantially than its peers in the industry, it will be able to increase its profitability. In other words, if the utility reduces its costs at a faster pace than what is implied by the I-X rate adjustment mechanism, it will see its net income increase. This aspect of the PBR plan mirrors market discipline in competitive markets, where firms focus on reducing their own costs rather than trying to influence prices charged to customers. The framework allows the utilities to retain (some) of those incremental profits. The framework also enables the utilities to manage their costs over the PBR term, including the timing, choice, and amount of costs deployed for operating the business, including decisions regarding the mixture of capital and operating expense to achieve intended operating outcomes.

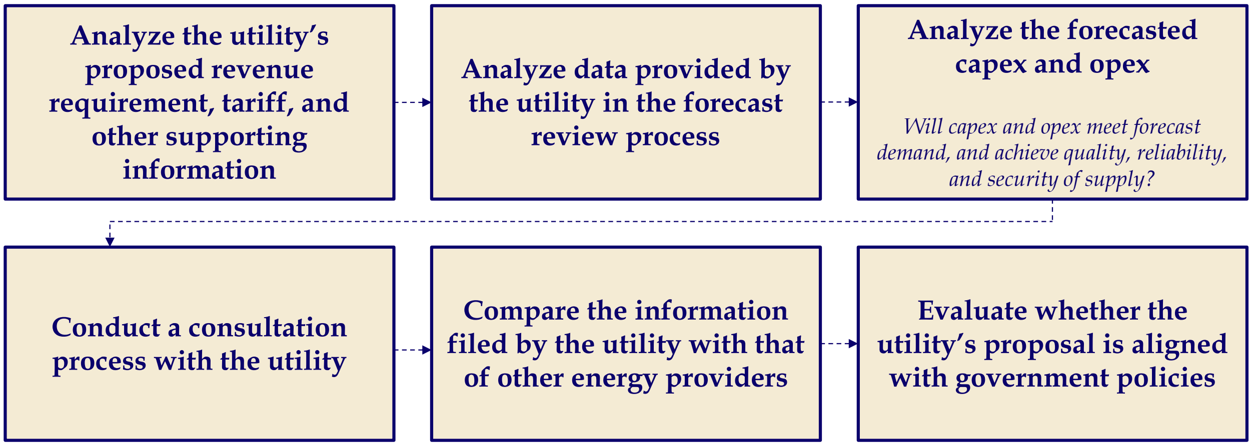
The use of the formulaic indexing rate formula reduces regulatory burden through a predictable annual rate adjustment, thereby avoiding intensive base rate reviews. The usual capital and operating costs are generally reflected in the formula's X factor. This means that there is no review needed to assess the utility's annual spending during the regulatory term for expenditures that fall under the I-X formula. The DPU only performs reviews of incremental investments related to grid modernization (discussed in Section 6.1.4) and adjustments to exogenous costs on an annual basis. This reduced regulatory burden benefits not only the utilities but also the regulator, and ultimately, the consumers.

7.1.2 Malaysia

International jurisdictions have developed yet other methods for reviewing utility spending. Malaysia is also under a PBR regime and implements a building blocks approach, like Australia and the UK. This means that expenditures are forecasted for the three-year term of the multi-year rate plan. The utility, Tenaga Nasional Berhad ("TNB"), must demonstrate that its forecasts are robust and accurate.

Suruhanjaya Tenaga, the Malaysian regulator, assesses forecasts of expenditures for the Regulatory Asset Base, or average starting and closed fixed assets, in three steps. In the first, the regulator inspects the efficiency and prudency of the utility's policies relevant to asset management, development, and replacement. Next, the regulator confirms alignment between expenditure forecasts and efficient asset policies. Lastly, it confirms alignment between capex and macro-economic factors, such as sales and demand growth. Figure 14 shows these steps.

Figure 14. Steps for determining whether capex and opex forecasts are efficient and prudent



Source: Suruhanjaya Tenaga

The regulator uses several tools to review and evaluate the utility's cost submissions. It takes a combined approach of benchmarking and trend analysis, historical cost performance, and decision on the efficiency and prudency of asset management policies to determine whether the utility's operating costs were efficient. These include the following:[74]

- **Trend analysis** – the use of trends in historical time series data for specific cost items of the utility to determine general patterns and the relationship between associated factors or drivers;

- **Methodology assessment** – assessment of the robustness of the models used and the related inputs, assumptions, and methodologies for developing expenditure forecasts;

- **Predictive modeling** – the use of statistical and econometric modeling and analytical techniques to determine the expected pattern of efficient costs over the forthcoming regulatory term for specific categories of expenditure;

- **Technical engineering reviews** – usually undertaken with the assistance of specialized technical consultants or experts;

- **Benchmarking, econometric, and statistical techniques** – these relate allowed costs to benchmarks established by reference to comparator entities.

[74] Suruhanjaya Tenaga. *Guidelines on Electricity Tariff Determination under Incentive-Based Regulation (IBR) for Peninsular Malaysia 2021*. Web. April 16, 2021. <https://www.st.gov.my/en/contents/files/download/152/Guidelines_on_Electricity_Tariff_Determination_Under_Incentive_Based_Regulation_(IBR)_For_Peninsular_Malaysia_2021_V2.pdf>. P. 47-48.

The regulator may also undertake an ex-post review of historical capex to assess prudency and efficiency. The ex-post capex assessment is generally limited to where there is material overspending; the materiality threshold is considered to have been met where the overspend exceeds 1% of the annual revenue requirement. The review entails a cost assessment and considers any procurement procedures used by the utility in delivering the investment projects. The regulator will examine the causes of the cost overrun and determine whether these causes can be ascribed to the actions of the utility or external factors outside of its control.[75] The regulator also considers the following in its evaluation of prudency and efficiency:

1. "Whether the expenditure was reasonably related to the requirements set by the [regulator] and/or under relevant laws, regulations, and license conditions.

2. Whether alternative ways of addressing requirements and needs were considered and justifiably excluded.

3. Whether accepted good industry practice was followed.

4. Whether the relevant [utility] acted prudently in procuring goods, works, and services at a reasonably low cost, including whether an appropriate competitive tendering process was followed.

5. Whether the timing of construction was appropriate having regard to current and projected demand and quality of service."[76]

The utility must demonstrate why the realized expenditure could not have been predicted at the time of developing the capex program and the setting of the annual revenue requirement.[77]

As a filing requirement, TNB submits Regulatory Accounts, a key submission from which the regulator assesses actual performance against capex, opex, and performance forecasts. The Regulatory Accounts are different from financial statements, considering asset depreciation and other revenues and expenses that are not subject to regulation. The utility must clarify any variances between forecast and actual capex, opex, and performance.[78]

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[75] Ibid. P. 61.

[76] Ibid. P. 62.

[77] Ibid. P. 61.

[78] Suruhanjaya Tenaga. *Review on Electricity Tariff in Peninsular Malaysia under the Incentive-based Regulation Mechanism (FY2014-FY2017)*. Web. Presented December 19, 2013. <https://www.st.gov.my/en/contents/presentations/tariff/1_ST_Proses%20semakan%20dan%20keputusak%20penetapan%20tarif%20elektrik%20di%20semenanjung%20malaysia.pdf>; Suruhanjaya Tenaga. *Electricity Tariff Regulatory Implementation Guidelines*. Web. January 2012. <https://policy.asiapacificenergy.org/sites/default/files/Electricity%20tariff%20regulatory%20implementation%20guidelines_0.pdf>.

Unlike in Massachusetts, Malaysia has established several tools to assess utility spending, both ex-ante and ex-post. This is because Malaysia uses the building blocks approach, which relies on forecasts and makes it challenging for the regulator to gather complete information about the utility's costs. Nevertheless, a cost forecast or building blocks approach can work if there are mechanisms in place to review the forecasts and spending.

7.1.3 Australia

Australia is also under PBR, and its price review process uses a propose-respond model where utilities put forward a price proposal and cost forecast that becomes the baseline that the regulator responds to. Unlike in the US, neither the national nor state regulators hold hearings in a formal legalistic sense with sworn evidence and legal representatives. The process can be best characterized as workshops or roundtables with a high degree of flexibility in the exact format and structure.

Australia, similar to the UK and Malaysia, uses a building blocks approach to determine revenue requirements. Efficient targets are embedded in the building blocks themselves and, therefore, in the projected revenue requirements before being converted into a price. It also has other components of PBR, such as flow-through (or pass-through mechanisms), incentives to pursue efficient capital and operating expenditure, and service target performance incentive schemes.

The Australian Energy Regulator ("AER") developed the so-called Expenditure Forecast Assessment Guidelines to assess utility capex and opex forecasts. In these guidelines, the AER uses several techniques comprising a holistic analysis that helps the regulator come to a conclusion on the reasonableness of the forecasts. These include benchmarking, methodology review, governance and policy review, predictive modeling, trend analysis, cost benefit analysis, and detailed project review (inclusive of an engineering review). The AER uses all or a select number of these techniques, depending on what is deemed necessary for the proposal being assessed.

There are three types of benchmarking analyses undertaken: economic benchmarking, category level benchmarking, and aggregated category benchmarking. The first uses total factor productivity, data envelopment analysis, and econometrics to assess the efficiency of inputs used to produce the utility's outputs; the result of this analysis is compared to the utility's historical performance on this assessment as well as the performance of peer companies. The second type benchmarks various levels of expenditure categories (such as total capex and opex, high-level expenditure like customer-driven capex, or unit costs for work like labor and materials) across utilities. Finally, in the third benchmarks looks at scale and density, measured by the amount of energy delivered by the utility or the amount of spending per kilometer of transmission line.

In methodology review, as the name implies, the regulator evaluates the methodology used by the utility to come to its forecasted expenditure amount. The regulator will look at assumptions, inputs, and models, and may adjust the methodology as it deems fit.

In terms of governance and policy review, the regulator compares the utility's governance, strategic planning, risk management, and asset management and prioritization with that of industry best practice. This technique alone would not be used by the regulator to approve a utility's forecast capex and opex spending.

Trend analysis refers to the use of historical data in a base-step-trend opex assessment to evaluate both capex (if expenditure tends to be consistent over time) and opex forecasts. The base-step-trend formula considers changes in real prices, output growth, and productivity; actual opex from the last year of the preceding regulatory period; an efficiency adjustment; and yearly step changes for costs not reflected in base opex or changes in prices, output, and productivity.

Predictive modeling consists of statistical and econometric analyses that are used to determine whether forecasted costs align with forecasted demand and categories of work. To this end, AER developed two models, called the repex model (condition-based modeling used to forecast asset replacement) and augex model (asset utilization modeling used to forecast network augmentation requirements).

Using the cost benefit analysis technique, the regulator determines (in terms of net present value) the efficiency of the utility's forecasts. In other words, this technique checks to see whether the utility's forecast is the lowest cost option relative to other cost options. This is an especially important technique for AER when assessing expenditure for asset categories or projects and programs that materially affect forecasted expenditure.

Finally, in a detailed project review, the regulator will assess specific project areas (or areas where the regulator deems review is required) or will randomly select projects for evaluation. The review may be informed by the results of the other aforementioned techniques.[79]

Australia, like Malaysia, has several tools at its disposal to ensure that a utility's forecasts are reasonable. However, Australia's administrative burden is higher with the building blocks approach than that of Massachusetts's indexing rate formula with the several reviews that the AER performs.

7.1.4 United Kingdom

PBR in the UK has been in force for more than two decades. Currently, it uses the RIIO ("Revenue = Incentives + Innovation + Outputs") model, which focuses on setting the revenue that delivers strong incentives, innovation, and outputs. It is a PBR model applied to both the gas and electricity transmission and distribution sectors. The RIIO model has several objectives related to performance improvements: (i) focusing on stakeholders in their decision-making process, (ii) investing efficiently to ensure continued safe and reliable services at a low cost, (iii) innovating to lower network costs for consumers, and (iv) supporting the government's environmental objectives of development of a low-carbon economy. It sets the outputs that distributors need to

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[79] Australian Energy Regulator. *Better Regulation; Expenditure Forecast Assessment Guideline for Electricity Distribution*. Web. August 2022. <https://www.aer.gov.au/system/files/AER%20-%20Expenditure%20forecast%20assessment%20guideline%20-%20distribution%20-%20August%202022.pdf>.

deliver on and the revenues they are allowed to collect for the eight-year period from April 1, 2015, to March 31, 2023.[80] RIIO may be broken down into the following main components:

1. **An MRP** - an eight-year rate period[81] that includes a revenue adjustment mechanism (which depends on utilities' performance against pre-set targets) and a Z factor component for unpredictable cost changes. Utilities are incentivized to spend efficiently as the cost-savings from delivering a project under budget are shared between the utility and customers;

2. **A total expenditure ("totex") approach**[82] - totex combines a portion of utility capex and opex into one regulatory asset that allows a rate of return on both; and

3. **Performance incentives** - Ofgem considers utility performance measures as reputational in that performance incentives facilitate the comparison of utilities against one another. However, a subset of these measures are financial incentives, as they tie utility's performance to tangible rewards and penalties.

The RIIO model uses the building blocks approach to determine the utilities' revenue requirements. It also includes the following mechanisms: rewards and penalties for specific performance targets, re-openers for high value projects that are 20% over the total allowance, flow-through non-controllable costs, as well as other incentives to encourage investments in technological improvements.

Under the RIIO model, utilities need to submit well-justified and detailed business plans to the regulator, Ofgem.[83] The business plans need to clearly articulate the outputs that the utilities plan on delivering during the regulatory term. It must prove that the outputs are integrally linked to the calculation of the proposed revenues. The utilities must also show that alternative pathways to delivering the required outputs were considered. In addition, they must demonstrate that the outputs were determined through a consultation process. Finally, the utilities must prove that

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[80] Ofgem. *RIIO-ED1 electricity distribution price control – overview of the regulatory instructions and guidance - revised*. April 16, 2018.

[81] For RIIO 1, but for RIIO 2, the term will be 5 years.

[82] Under RIIO's totex approach, the utilities are incentivized to consider whole life costs, rather than being driven to choose between capex and opex. A capitalization ratio is set between opex and capex that is applied during the regulatory period. This ratio sets how much revenue will be expensed ("fast money") versus how much revenue will be added to the regulatory asset base ("slow money") at the onset of the regulatory period. This framework allows the utilities to be indifferent when choosing between capex and opex expenditure because this choice will not impact how the allowed revenue is determined.

[83] According to the RIIO Handbook, a business plan is considered well-justified when utilities demonstrate the following: focus on output delivery, clear and well-evidenced case for their proposals, the link between costs and primary outputs, consideration of the longer-term, value for money, openness to other available options, evidence of stakeholder engagements and a consideration of how to work with others in the industry.

their business plans are cost-efficient and provide long-term value for money. Figure 15 lists some of the items that the utility needs to explain thoroughly in the business plan.

Figure 15. Items that need to be explained in a utility's business plan

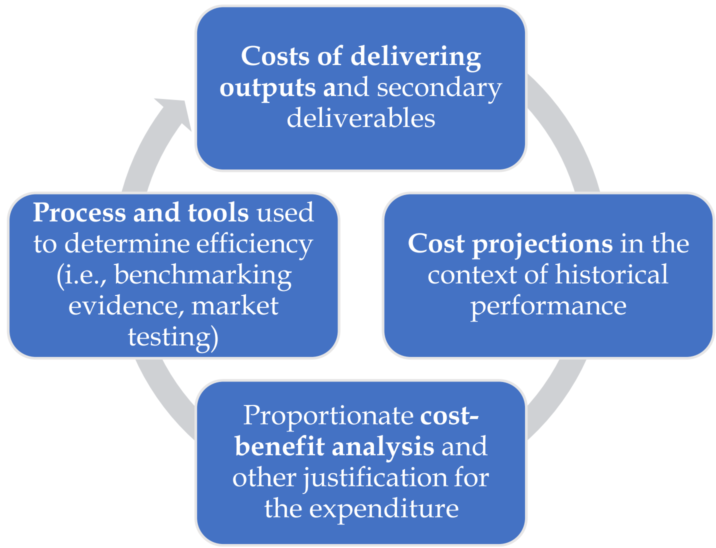
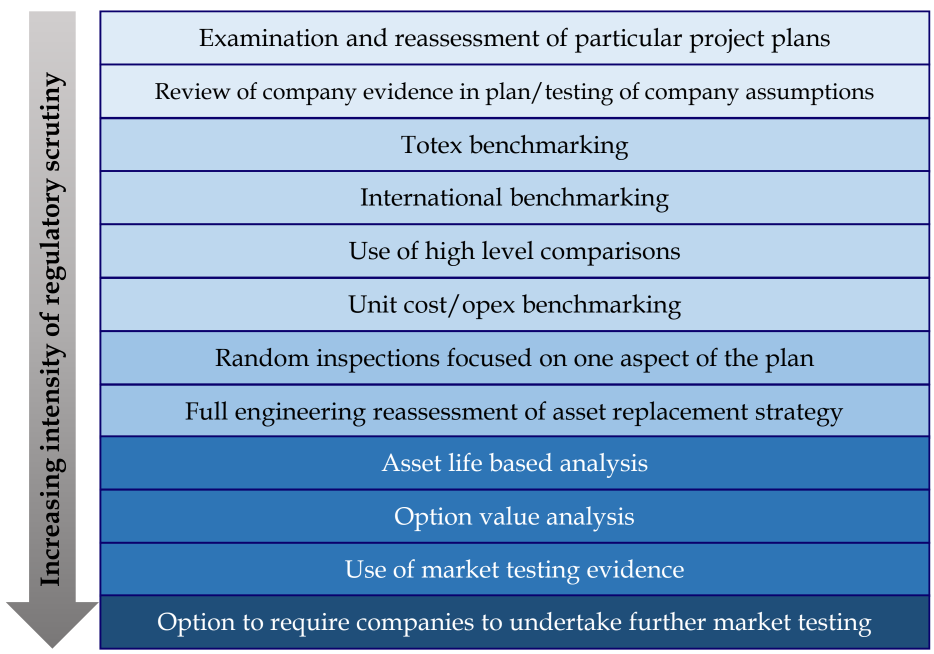


Figure 16. Assessment toolkit



Source: Ofgem. *Handbook for implementing the RIIO model*. October 4, 2010.

Ofgem uses multiple tools with various degrees of regulatory scrutiny in assessing the utility's proposed expenditures. Examples of these tools are shown in Figure 16. This toolbox approach was adopted by the regulator as a way of ascertaining whether a utility's costs are efficient and "give long-term value for money." The toolbox consists of statistical analyses of totex, analyses on specific types of costs, qualitative assessments (such as scheme justification), and benchmarking of utilities against their peers (where the benchmark is set not at the most efficient utility but rather at the calculated upper quartile of efficiency).

Ofgem chooses what assessment tools it uses based on the quality of the business plans received and the specific aspects of the plans that cause it concerns. It also utilizes qualitative and quantitative assessments, utilities' narratives and supporting evidence, historical costs, and performance data and forecasts. Ofgem acknowledges that no single measure of total cost is ideal and therefore it uses alternative measures as cross checks. Furthermore, sensitivity analyses are also performed to ensure robustness of the assessment.

In an example, Ofgem conducted an assessment of utility costs in 2014 in which it made use of three different analytical tools (what it calls models): two so-called totex models and one disaggregated model. The assessment consisted of the following steps:

- First, before running the totex models, the regulator conducted a regression analysis that used historical and forecast data (with greater weight placed on forecast data) and a time trend to evaluate whether costs were efficient relative to a composite scale value;

- Second, the regulator ran the two totex models. In the "top-down" totex model, high-level cost drivers were used. The "bottom-up" totex model, in contrast, used activity-based cost drivers from the disaggregated analysis. Both provide aggregate views of efficiency by "internalizing" capex and opex tradeoffs and being neutral to the ways in which costs are categorized;

- Lastly, in the disaggregated model, Ofgem had a suite of techniques with which to review non-regressed cost activities and to tailor the review of the utility's spending. In general, these include quantitative, qualitative, and technical assessments. Specifically, the techniques may include regression analysis, ratio analysis, trend analysis, and technical assessments. The regulator also had to option to retain engineering consultants to review the efficiency of the utility's costs. The results of these analyses were summed;

- A combination of these three models was then used for benchmarking, where 50% weight was placed on the totex models (equally split between the "top-down" and "bottom-up" approaches) and the remaining 50% on the disaggregated analysis. Additional normalizations and adjustments were added on top of these results.[84]

Similar to Australia, the UK has instituted several mechanisms to review the utilities' business plans and spending. However, the regulatory burden for the utilities and the regulator is rather

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[84] Ofgem. *RIIO-ED1: Final determinations for the slow-track electricity distribution companies; Business plan expenditure assessment*. Web. November 28, 2014. <https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/riio-ed1_final_determination_expenditure_assessment_0.pdf>; Ofgem. *Guide to the RIIO-ED1 electricity distribution price control*. Web. January 18, 2017. <https://www.ofgem.gov.uk/sites/default/files/docs/2017/01/guide_to_riioed1.pdf>.

high. In fact, its ratemaking process typically takes 30 months, from the time that Ofgem announces the key issues for the next regulatory process to the implementation of incentive-based regulation. Expert consultants also have to be hired by the utilities to help prepare their business plans and by the regulator to help develop the various PBR mechanisms, review utility filings, and ensure that the various PBR mechanisms in play are working together effectively and as intended.

7.2 Clawback of under-spending

Some jurisdictions use cost forecasts to project the revenue requirement associated with capital investments, but couple the forecasts with a one-way reconciliation—or clawback—mechanism. This clawback mechanism reduces the benefit that the utility receives from inflating its cost projections and protects customers from utility under-spending. It also encourages the utility to keep costs below projections and ensures that over-spending is not approved until a prudency review is conducted in the subsequent rate case. Another advantage of the clawback mechanism is that it allows utilities to share any savings resulting from lower service-related expenditures with customers following the next rate case.

Nevertheless, this mechanism does not fully resolve the issue of over-forecasting of costs and provides no incentive to increase efficiency.[85] Furthermore, the clawback underspend mechanism may increase administrative burden given the additional rate filings needed to determine the amount of underspend. Two examples of the clawback mechanism as implemented in US jurisdictions are discussed in the subsections below.

7.2.1 New York

In 2010, New York adopted the net capital plant reconciliation (i.e., clawback) mechanism, which returns the benefits of capex underspend to consumers.[86] Utilities file MRPs that outline their capital spending for three years at a time. Once approved, utilities immediately start earning returns (profits) on capital outlays. At the end of the rate plan period, if the utilities have spent less than expected, the State of New York Public Service Commission ("NYPSC") takes back the profits associated with the unspent capital.[87] Since the clawback provides that earnings from

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[85] Whited, Melissa and Cheryl Roberto. *Multi-Year Rate Plans: Core Elements and Case Studies*. Synapse Energy Economics, Inc. Prepared for Maryland PC51 and Case 9618. Web. September 30, 2019. <https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf>. P.16.

[86] State of New York Public Service Commission. *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. Case 09-E-0428. Issued and Effective March 26, 2010.

[87] Katofsky, Ryan. "New York Gets into the Details of a New Business Model for Utilities." Advanced Energy Economy. Web. November 5, 2015. <https://blog.aee.net/new-york-gets-into-the-details-of-a-new-business-model-for-utilities>.

capital programs that fall below approved levels must be returned to customers, utilities see no financial benefit from investing less than anticipated when their authorized revenues were set.

The NYPSC describes this mechanism for Consolidated Edison as follows:

> "If the Company's actual average net plant in service for each of the three categories of capital expenditures is less than that category's projected average plant-in-service balance for the first-rate year (or collectively for the second and third years), the Company will defer the carrying costs associated with the difference for the benefit of ratepayers. If the Company exceeds the net plant-in-service targets, it must absorb the related carrying costs during the term of the rate plan.
>
> Con Edison must justify the need for, the reasonableness of, and its inability to reasonably avoid any such over-target expenditures in its next rate case filing. In addition, the revenue requirement associated with any such Commission-approved over-target expenditures from Rate Year 1, after the term of the rate plan and for the book life of the investment, will be calculated based on an assumption that the over-target expenditures were not financed by both common equity and debt, but rather solely by debt."[88]

In 2014, the NYPSC launched Reforming the Energy Vision ("REV"), a regulatory reform program with a particular focus on energy efficiency and integrating DRs. Growth in system load typically requires significant capital investments. Under REV, utilities are encouraged to pursue cost-effective DER alternatives to capital investments. However, the regulator notes that DER alternatives are normally achieved through operating expenditures, so "the ordinary operation of the clawback mechanism would result in utilities forfeiting their capital earnings with no offsetting compensation, and a risk of absorbing the DER operating expenses that were not reflected in base rates."[89]

For this reason, a modification to the state's clawback mechanism was implemented under REV. The NYPSC approved for utilities that adopt DER alternatives over capital projects the ability to retain the earnings on capital that are already reflected in base rates. The regulator stressed that any retention of earnings on capital must be directly linked to a demonstration of the DER alternative that replaced the capital project. This continues to involve sharing of savings over a certain number of years, rather than the utility retaining all savings over the course of a given rate plan. Where MRPs are currently underway, a utility adopting a DER alternative to a capital project may receive comparable treatment upon filing a detailed compliance document

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[88] State of New York Public Service Commission. *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. Case 09-E-0428. Issued and Effective March 26, 2010. P. 11.

[89] State of New York Public Service Commission. *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.* Case 14-M-0101. Issued and Effective May 19, 2016. P. 99.

demonstrating how an operating expense solution is being used to cost effectively offset and delay capital investment included in the rate case capital plan.[90]

This modification means that if the utility shows that a portion of its capital budget was avoided due to a service expense for DER, the clawback mechanism will not be implemented on that portion of the budget. The utility will retain the avoided portion of the capital budget and associated earnings and pay for the service expense without additional rate recovery. Thus, as long as the yearly service expense is less than the yearly amount of amortization and carrying costs in the capital budget, the utility will benefit from retaining the savings. During the next rate case, the elements of the revenue requirement associated with the avoided capital are removed and the cost of the service contract is added to O&M expenses.[91]

Clawback is only effective for the duration of a rate plan. In the case of New York, it is expected that the utility's operating budget should increase every three years to accommodate expenses related to DER.[92] While the utility's increased operating budget covers DER expenses, the utility is unable to retain savings from capital investments avoided. Here, the utility can only earn on savings for the three-year-long duration of the MRP.

This means that, in New York, the timing of capital investment is key. A capital investment made before the start of an MRP will be able to earn on savings for the duration of the MRP. An investment made at the end of an MRP will have little to no time to enjoy potential earnings under the clawback mechanism. This drawback can be mitigated through appropriate regulatory adjustments.

7.2.2 Minnesota

In 2020, the Minnesota Public Utilities Commission approved three different categories of refunds to customers by the Northern States Power Company d/b/a Xcel Energy ("Xcel")—net operating loss, incentive plan, and property tax true-up refunds. Xcel has been responsible for submitting annual compliance filings reconciling these costs in relation to the rate base since as early as the 1990s; it is based on these filings that the Minnesota regulator ensures that any under-spending is returned to ratepayers.

In an example, in May 2012, the Minnesota PUC established a deferred tax asset from Xcel's net operating loss connected with modified bonus depreciation provisions originating in the 2010 tax code. In its 2018 annual compliance filing, Xcel found that its 2017 annual revenue requirement reduction was larger than authorized (i.e., the company understated its 2017 net annual revenue

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[90] Ibid. P. 101

[91] Advanced Energy Economy. *Optimizing Capital and Service Expenditures; Providing utilities with financial incentives for a changing grid*. A 21st Century Electricity System Issue Brief. Web. June 5, 2018 (updated). <https://info.aee.net/hubfs/PDF/Opex-Capex.pdf>. P.9.

[92] Ibid.

requirement reduction), which would be refunded to customers in the form of one-time bill credits with interest.

In another example, Xcel also prepares annual compliance filings relevant to the company's Annual Incentive Plan. Xcel has been obligated to submit such compliance filings since 1993/1994, when the Minnesota PUC called for the company to evaluate the "operation and performance of its incentive compensation plan."[93] In its 2019 compliance filing covering its 2018 Incentive Compensation Plan, Xcel found that a cap on incentive payouts resulted in a compensation payment that was lower than the amount in base rates. This amount was refunded to customers, by class and based on the 2018 rate base, in the form of a one-time bill credit.

Similarly, Xcel submits compliance filings related to its property taxes. Here, Xcel reconciles the difference between property taxes paid and the amount in base rates. When in 2019 the company found that its 2018 property taxes were lower than what was allowed in base rates, it refunded the difference in these two amounts to customers, with interest.[94]

Xcel is also liable to refunding any underspent amounts (or implementing a charge for under-collection) calculated in its sales true-up reconciliation filing. For example, the Minnesota regulator approved Xcel's 2019 rates to be calculated using the 2019 revenue requirement and 2016 weather normalized actual sales for all customer classes, adjusted for "full decoupling for the decoupled classes and the true-ups to actual sales for the non-decoupled classes, subject to the three percent cap…."[95] The three percent cap excludes fuel and riders. As per this methodology, sales true-up, calculated separately for the decoupled and non-decoupled classes, is the difference between actual revenues and approved plan year revenues. If actual revenues are higher than approved plan year revenues, then Xcel refunds the difference to ratepayers. If actual revenues are lower, then Xcel collects the difference from ratepayers. A Minnesota PUC order allowed Xcel to collect (not refund) its calculated true-up amount through a surcharge on customer bills.[96]

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[93] Minnesota Public Utilities Commission. Docket No. GR-15-826. Web. Issued May 7, 2020. <https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7bF0E5EF71-0000-C239-A984-E373A324D80A%7d&documentTitle=20205-163007-02>.

[94] Ibid.

[95] Minnesota Public Utilities Commission. Docket No. E-002/GR-15-826. Web. Service date May 22, 2020. <https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b00233E72-0000-C21A-9A4C-96D61916185A%7d&documentTitle=20205-163433-01>.

[96] Ibid.

7.3 The UK's Information Quality Incentive scheme

In addition to the mechanisms discussed in Section 7.1.4, Ofgem also uses the IQI scheme to further encourage utilities to produce "high quality and well justified business plans" and accurate expenditure forecasts through a reward and penalty framework.

Such mechanism provides incentives for a utility to not only propose efficient and prudent costs as part of its regulatory review, but also to realize timely investment when needed (rather than to game the system and time investment with PBR terms). The IQI, which has become a key feature of the UK PBR approach, specifically addresses the information asymmetries problem that regulators have historically been concerned with under the COS and, to some degree, under the building blocks approach.

Ofgem uses the IQI to encourage utilities to create business plans that reflect the best available information about their future efficient expenditure requirements. The IQI incentivizes utilities in two ways: (i) by giving additional income to utilities whose forecast spend is close to Ofgem's assessment, and (ii) by providing higher incentive rates to utilities that match forecasts than utilities with higher capex forecasts.[97] Therefore, under the IQI scheme, utilities get rewarded for forecasting accurately and spending lower than what they proposed. In addition, Ofgem also uses the IQI scheme as a financial deterrent against the submission of inflated expenditure forecasts.[98]

The IQI has three main elements, namely:

1. "Utilities receive an upfront financial reward or penalty, depending on their forecast relative to Ofgem's assessment of efficient expenditure;

2. Utilities that submit better forecasts (i.e., closer to Ofgem's view of efficient cost) receive a higher efficient incentive rate; and

3. Allowed expenditure is based 75% on Ofgem's benchmark view and 25% on the utilities' forecast."[99]

Figure 17 shows the IQI matrix and presents how utilities earn the highest income by accurately forecasting their intended capex spend (this is highlighted in green).[100] The first line in the table ("DNO-Ofgem Ratio") is the utility's forecast expenditure as a percentage of Ofgem's modeled view. A low ratio indicates a more efficient forecast (or better-quality forecast).

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[97] Ibid

[98] Ofgem. *Handbook for implementing the RIIO model.* October 4, 2010. P. 66.

[99] Ibid. P. 37.

[100] Ofgem. *Electricity Distribution Price Control Review Policy paper – Supplementary appendices.* December 5, 2008. P. 111.

The efficiency incentive (second line) increases as the ratio becomes lower, and vice versa. The efficiency incentive rate for a utility will depend on the ratio between its expenditure forecast and Ofgem's assessment of its expenditure requirements.

Figure 17. IQI matrix

DNO: Ofgem Ratio	90	95	100	105	110	115	120	125	130
Efficiency Incentive	65%	63%	60%	58%	55%	53%	50%	48%	45%
Additional income (£/100m)	3.1	2.4	1.7	0.9	0.1	-0.8	-1.8	-2.8	-3.9
Allowed expenditures	**£97.5**	**£98.75**	**£100**	**£101.25**	**£102.5**	**£103.75**	**£105**	**£106.25**	**£107.5**
Actual Expenditures									
£90	£7.95	£7.90	£7.70	£7.40	£7.00	£6.40	£5.70	£4.90	£4.00
£95	£4.70	£4.76	£4.70	£4.50	£4.20	£3.80	£3.20	£2.50	£1.70
£100	£1.50	£1.60	£1.70	£1.60	£1.50	£1.10	£0.70	£0.10	-£0.60
£105	-£1.80	-£1.50	-£1.30	-£1.20	-£1.30	-£1.50	-£1.80	-£2.20	-£2.80
£110	-£5.10	-£4.60	-£4.30	-£4.10	-£4.10	-£4.10	-£4.30	-£4.60	-£5.10
£115	-£8.30	-£7.70	-£7.30	-£7.00	-£6.80	-£6.70	-£6.80	-£7.00	-£7.30
£120	-£11.60	-£10.90	-£10.30	-£9.90	-£9.60	-£9.40	-£9.30	-£9.40	-£9.60
£125	-£14.80	-£14.00	-£13.30	-£12.70	-£12.30	-£12.00	-£11.80	-£11.70	-£11.80
£130	-£18.10	-£17.10	-£16.30	-£15.60	-£15.10	-£14.60	-£14.30	-£14.10	-£14.10
£135	-£21.30	-£20.20	-£19.30	-£18.50	-£17.80	-£17.20	-£16.80	-£16.50	-£16.30
£140	-£24.60	-£23.40	-£22.30	-£21.40	-£20.60	-£19.90	-£19.30	-£18.90	-£18.60
£145	-£27.80	-£26.50	-£25.30	-£24.20	-£23.30	-£22.50	-£21.80	-£21.20	-£20.80
£150	-£31.10	-£29.60	-£28.30	-£27.10	-£26.10	-£25.10	-£24.30	-£23.60	-£23.10

Note: DNO stands for distribution network operator in the UK, which is the same as distribution utility. Also, for RIIO-Electric Distribution 1 ("ED1"), Ofgem adjusted the break-even point in the IQI matrix to an IQI score of 102.9 instead of 100. This means that a utility that forecasts 2.9% above Ofgem's efficient cost benchmark and achieves its forecast will earn its cost of capital but no additional reward or penalty.

Source: Ofgem. *RIIO-ED1: Final determination for the slow-track electricity distribution companies*. Web. November 28, 2014. <https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/riio-ed1_final_determination_overview_-_updated_front_cover_0.pdf>. P. 17.

The third line shows the additional income *(penalty)* that the utility receives if it meets or exceeds *(*fails to meet*)* the allowed expenditure. This additional income or deductible is calculated using the formula shown in Figure 18.

Figure 18. Formula for the reward or penalty

$$\text{Reward or penalty} = \left(\text{Allowed expenditure} - \text{Actual expenditure}\right) \times \text{Efficiency incentive} + \text{Additional income}$$

Source: Ofgem. *Handbook for implementing the RIIO model*. October 4, 2010.

For example, suppose that a utility has an allowed expenditure of £100 million and its spending aligns with Ofgem's assessment. If the utility were able to spend the same amount that it had forecasted, then it would be rewarded £1.7 million. If it were able to control its costs and spend less than the allowed expenditure (in this case, £90 million), then it would get to keep £7.7 million. This amount, shown in Figure 19 below, is calculated using the formula above.

On the other hand, if a utility spent £110 million, which is £10 million more than its allowed expenditure, then it would not be eligible for the additional income and would even be penalized at a price tag of £4.3 million. Figure 20 shows how the penalty was derived using the formula provided above.

Figure 19. Sample calculation of a reward

$$\text{Reward or penalty} = \left(\text{Allowed expenditure} - \text{Actual expenditure}\right) \times \text{Efficiency incentive} + \text{Additional income}$$

$$\text{Reward or penalty} = \left(\text{£100 million} - \text{£90 million}\right) \times 60\% + \text{£1.7 million}$$

$$\text{Reward} = \text{£1.7 million}$$

Figure 20. Sample calculation of a penalty

$$\text{Reward or penalty} = \left(\text{Allowed expenditure} - \text{Actual expenditure}\right) \times \text{Efficiency incentive} + \text{Additional income}$$

$$\text{Reward or penalty} = \left(\text{£100 million} - \text{£110 million}\right) \times 60\% + \text{£1.7 million}$$

$$\text{Penalty} = -\text{£4.3 million}$$

Although the IQI scheme has its advantages in incentivizing utilities to submit robust forecasts, it is a complex mechanism to put together and requires various tools (as listed in Figure 25) to develop the matrix.

7.4 The Philippines' price-linked incentive scheme

Another mechanism relevant to this discussion is the price-linked incentive scheme used in the Philippines. Although it is not an incentive directly related to the utility's forecasts, it is an interesting scheme that links utility performance to annual revenue requirements.

In 2006, a price-cap regulation for electric distribution utilities was passed in the Philippines, replacing the COS methodology. This PBR framework was applied to the 19 investor-owned distribution utilities in the country. The Philippines uses a building blocks approach, like the UK, where the annual revenue requirements are approved before the start of the regulatory term and verified every regulatory year. The utility's performance is evaluated annually, and the results are considered in this annual verification process.[101]

One of the two performance incentive schemes[102] that is reviewed annually is the price-linked incentive scheme, where the utility's performance is evaluated against several reliability and service performance measures. The utilities are financially rewarded if performance levels exceed pre-determined targets. Conversely, the utilities are penalized if performance levels fail to meet the set targets. These rewards and penalties adjust the utilities' annual revenue requirements, as discussed below. There is also a cap on how much the utilities can be rewarded and penalized to avoid unintended financial consequences.

The performance incentive factor is a weighted performance measure based on the performance levels achieved against several indices over the calendar year preceding each year within the regulatory term. These indices include reliability and service performance measures, as listed in Figure 21.

The formula for the service performance factor (or the "S factor") is based on a weighted sum of the indices mentioned above and is calculated as illustrated in Figure 22. An example of the weighting used for each component is shown in Figure 23. The final weightings are determined during the regulatory reset process (also known as rebasing) for the next regulatory term.

Utilities are required to track their performance for each metric, as the data is used when determining the final performance bands for the incentive scheme to be implemented in the next regulatory term. Five discrete performance bands will be used for each performance metric, as shown in Figure 24. Performance in each of these bands results in the allocation of a simple performance assessment value to the index being assessed. These are the "Perf" values shown in the S formula in Figure 22. Figure 25 shows an example of how the performance assessment band is set for SAIFI performance. This is done for all the other metrics listed in Figure 21.

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[101] Manila Electric Company. *Performance-Based Regulation (PBR).* Web. Accessed October 25, 2022. <https://www.erc.gov.ph/Files/Render/media/PBR%20Meralco%20Sep%2030,%202019.pdf>. P. 51.

[102] The other performance scheme is the guaranteed service level ("GSL") scheme, where utilities must provide minimum service standards to customers. If these standards are not met, the utilities are obligated to pay consumers. The GSL payments are based on the performance target level adopted, the number of customers for which the utility missed its targets, the total annual revenue requirement allowed, and the weighting allowed for each index. There is no cap on GSL payments.

Figure 21. Metrics included in the price-linked incentive mechanism

Index or Metric	Description
SAIFI	System average interruption frequency index
CAIDI	Customer average interruption duration index
Planned SAIDI	System average interruption duration index for planned or pre-arranged outages
Voltage regulation	Measure of the probability of measured voltage level failing outside the +/- 10% regulation
System losses	Technical and non-technical losses falling below 9.5% (positive incentive to further reduce losses only, as this is covered in other programs already)
Time to process applications	Average time to process applications for regulatory services (standard connections)
Time to connect premises	Average time to provide connection, after all administrative requirements have been met
Call-center performance	Average time for call-center to respond to calls

Source: Philippine Energy Regulatory Commission. *Performance-Based Regulation of the Philippines Electricity Distribution Company Regulatory Training Course*. Session 3B – Performance Incentive Scheme. Web. November 2007. <https://www.erc.gov.ph/ContentPage/201>. P. 12.

Figure 22. The formula of the S factor

$$S_t = \frac{\left[S_{SAIFI,t} + S_{CAIDI,t} + S_{SAIDI,t} + S_{VoltViol,t} + S_{Sysloss,t} + S_{Process,t} + S_{Connect,t} + S_{call,t}\right] \times 0.025ARR_t}{FQ_t}$$

Where:

- **0.025ARR**$_t$ is the allowed annual revenue for Regulatory Year t
- **FQ**$_t$ is the total amount of energy (expressed in kWh) that is forecast to be delivered to Distribution Connection points during Regulatory Year t

Each S component is calculated as:

$$S_{SAIFI,t} = W_{SAIFI} \times Perf_{SAIFI,t-1}$$

Where:

- **W** is the weighting given to this S-component
- **Perf** refers to the "performance value," or to the corresponding component's performance assessment for the calendar year ending on December 31 of Regulatory Year t-1 (i.e., Regulatory Year t's rewards/ penalties will be based on the performance of Regulatory Year t-1)

Other S components share similar calculations to $S_{SAIFI,t}$

Figure 23. Example weightings of each performance metric

Component	Symbol	Weighting
SAIFI (planned & unplanned)	W_{SAIFI}	0.20
CAIDI (planned & unplanned)	W_{CAIDI}	0.20
SAIDI (planned & unplanned)	W_{SAIDI}	0.15
Voltage regulation	$W_{VoltViol}$	0.10
System losses	$W_{Sysloss}$	0.05
Time to process applications	W_{Proc}	0.10
Time to connect premises	W_{con}	0.10
Call-center performance	W_{Call}	0.10

Source: Philippine Energy Regulatory Commission. *Performance-Based Regulation of the Philippines Electricity Distribution Company Regulatory Training Course*. Session 3B – Performance Incentive Scheme. Web. November 2007. <https://www.erc.gov.ph/ContentPage/201>. P. 11.

Figure 24. Performance assessment band

Performance band	Description	Performance value
1	Performance greatly below target	-1.0
2	Target not achieved	-0.5
3	Performance as per expectation	0
4	Target exceeded	0.5
5	Target greatly exceeded	1.0

Source: Philippine Energy Regulatory Commission. *Performance-Based Regulation of the Philippines Electricity Distribution Company Regulatory Training Course*. Session 3B – Performance Incentive Scheme. Web. November 2007. <https://www.erc.gov.ph/ContentPage/201>.

The regulator, the Philippine Energy Regulatory Commission, sets the performance target for each performance metric as part of its decision in the rate case. For each performance metric, the target will be set either:

1. based on the utility's historical performance level that is the average annual performance for the five-year period; or

2. based on a utility's improvement over historical performance levels against an index that is, as determined by the regulator, itself based on benchmarking against the performance of the other privately-owned electric distribution utilities and/or similar international utilities.

Figure 25. Example of setting of performance bands for SAIFI performance

SAIFI	
Average SAIFI value	Average annual SAIFI for a Regulated Distribution System for the Regulatory Term
Standard deviation	Standard deviation of the annual SAIFI values for the Distribution System for the 10 calendar years leading up to the regulatory term
Performance greatly below target	Annual SAIFI more than 2 standard deviations above the SAIFI average
Target not achieved	Annual SAIFI more than or equal to 1 standard deviation, but less than 2 standard deviations, above the SAIFI average
Performance as per expectation	Annual SAIFI between or equal to 1 standard deviation above and 1 standard deviation below the average value
Target exceeded	Annual SAIFI more than 1 standard deviation, but less than or equal to 2 standard deviations, below the SAIFI average
Target greatly exceeded	Annual SAIFI more than 2 standard deviations below the SAIFI average

Source: Philippine Energy Regulatory Commission. *Performance-Based Regulation of the Philippines Electricity Distribution Company Regulatory Training Course*. Session 3B – Performance Incentive Scheme. Web. November 2007. <https://www.erc.gov.ph/ContentPage/201>.

The calculated S factor is then added to the price formula,[103] as shown in Figure 26. It is possible for the S factor to be positive, negative, or zero, depending on whether the utility's actual performance has exceeded performance targets. The maximum level of the rewards or penalties under the price-linked incentive scheme in any year is capped at 2.5% of the annual revenue requirement for that regulatory year. This ceiling is reflected in the S factor formula shown in Figure 22.

[103] The Philippines calls this rate formula the "price control formula."

This scheme is relatively straightforward. Nevertheless, coming up with a similar tool that is jurisdiction- and context-specific requires robust analysis, particularly in setting the performance bands, selecting the metrics to be included in the S factor, and determining the weightings of each metric.

Figure 26. Rate formula and the S factor

$$MAP_t = [MAP_{t-1} \times (1 + CWI_t - X)] + S_t - K_t + ITA_t$$

Where:

MAP = maximum average price for year t (or this year's price per unit of electricity)

MAP_{t-1} = previous year's price (per unit of electricity)

CWI_t = index of change in Consumer Prices

X = efficiency (or smoothing factor)

S = service performance incentive factor

K = correction for revenue over- or under-recovery in previous year

ITA = correction for tax over- or under-recovery in the previous year

Source: Philippine Energy Regulatory Commission. *Performance-Based Regulation of the Philippines Electricity Distribution Company Regulatory Training Course*. Session 1B – The Building Block and Price-Setting Methodology. Web. November 2007. <https://www.erc.gov.ph/ContentPage/201>. P. 34.

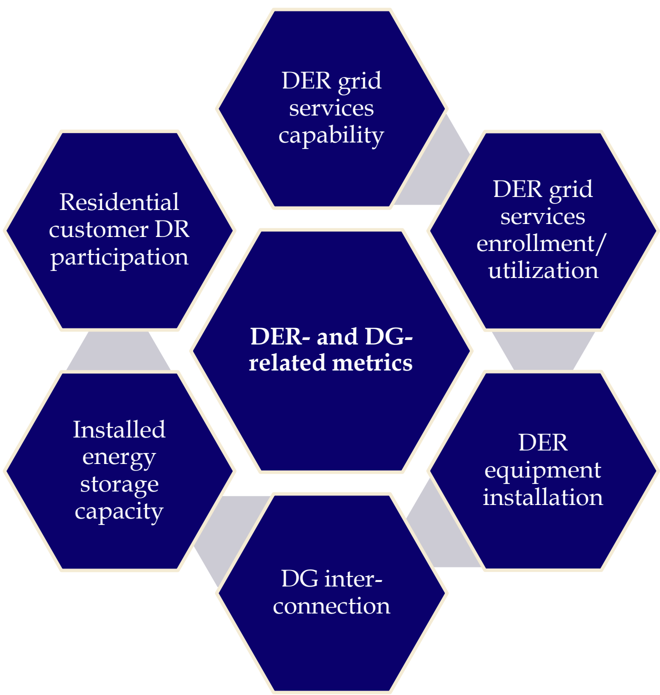
8 Performance incentive mechanisms

The PIM categories of interest to Commission staff relate to (i) DERs and DG, (ii) the responsiveness of utilities to field requests, and (iii) the utility's response to storms and other major outage events. The sections below build on the explanation of performance metrics give in Section 5.2.2 by providing sample metrics from these three categories that are in use in various US jurisdictions. These sample metrics are not exhaustive and are illustrative, only.

8.1 DER/DG PIMs

Several US states have implemented DER and DG-related PIMs. These PIMs—which tend to be tracking- or rewards-based, only—help to support a state's environmental, emissions, and/or energy efficiency goals and programs. They specifically seek to increase the speed with which DER/DG systems interconnect with the grid and increase the number of customers who take part in DER/DG-related programs.

Figure 27. Sample categories of DER/DG PIMs and scorecards



8.1.1 Hawaii

Hawaii has several scorecards and PIMs relevant to DERs/DG.

Intended to improve customer experience, the total **DER Interconnection Time** scorecard measures the average number of calendar days that it takes the utility to interconnect DER systems that are less than 100 kW in size. The Hawaii regulator set targets (in number of days per calendar year) that it expects the utility to achieve; the target for each successive year is lower than the last, indicating the regulator's desire for the utility to improve interconnection timelines. The regulator also caps the maximum dollar value of both the award and penalty for which the utility is liable.

DER Grid Services Capability, Enrollment, and Utilization is a reported metric that measures the total number of MWs of DER systems with the following traits: they can provide grid services, are enrolled in grid services programs, and are enrolled in grid services programs.

Lastly, **DER Curtailment**, as the name implies, is the total number of MWs of DER curtailment resulting from either partial curtailment or power reductions.

8.1.2 New York

New York adopted a rewards-only **DER Utilization** PIM that incentivizes the utility to work with third parties to expand DER systems—which include rooftop solar installations, community solar projects, battery and ice energy storage systems, and wind power—in its service territory. The PIM measures the amount of MWh of energy produced, consumed, or discharged from DER systems, and sets minimum, midpoint, and maximum achievement targets from a baseline goal legislatively established in the New York Climate Leadership and Community Protection Act. With respect to these three-tiered targets, the higher the target achieved by the utility, the higher the reward for which it is eligible.[104]

8.1.3 Rhode Island

Rhode Island has established scorecards and both rewards-based and tracking-only PIMs relevant to DERs.

For instance, under the DER category, the state introduced the **CO_2: Consumer Electric Vehicles** PIM, which measures the incremental number of tons of CO_2 emissions avoided because of the utility's existing initiative on electric transportation. This metric was determined based on estimations of EV uptake in the state using the US Energy Information Administration's ("EIA's") projection of EV sales in New England. The utility is responsible for tracking and reporting the incremental number of EVs adopted above the company's forecast, determining the proportion of new registrations that are battery EVs ("BEVs") versus plug-in hybrid EVs ("PHEVs"), and applying CO_2 emissions reductions values (as agreed upon by the regulator) to each of the BEV and PHEV values. A similar PIM—**Light Duty Government and Commercial Fleet Electrification**--measures the incremental increase in light-duty vehicles resulting from the utility's electric transportation initiative. A third type of DER-related scorecard, called **DER-Installed Energy Storage Capacity**, tracks the incremental amount of installed storage capacity.

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[104] State of New York Public Service Commission. *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service. Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans*. Case 17-E-0238. Issued and Effective March 15, 2018.

In terms of DG, in support of the transition of the power sector, Rhode Island has also introduced the **DG Interconnection – Time to Interconnection Service Agreement ("ISA")** scorecard. This metric tracks, for each interconnection type, the number of business days it takes to implement distribution system modifications from the signing of the ISA. **DG-Friendly Substation Transformers**, on the other hand, is a PIM that tracks the number of completed installations that support the timely interconnection of DG facilities (called "3VO" installations).

In 2018, Rhode Island also adopted the **System Efficiency: Annual MW Capacity Savings** PIM, where the utility can earn rewards for achieving set minimum, mid, and maximum targets (in MW), up to a maximum dollar amount as ordered by the state regulator. This PIM seeks to achieve annual peak capacity savings (in MW), specifically to avoid capacity coincidence with ISO-NE's peak hour. Several resources may participate under this PIM: demand response, incremental net-metered behind-the-meter solar generation above the utility's forecasted levels, incremental energy storage, and other demand-reducing activities like non-wires alternatives or collaboration with third parties. The utilities can implement activities relevant to this PIM to residential, commercial, and industrial customers.[105]

8.2 Responsiveness PIMs

Utilities in various US jurisdictions have implemented PIMs relevant to customer service or customer experience. Many of these tend to be penalty-based or tracking, only. Such metrics include, but are not limited to, calls answered with a specified time, interconnection experience, billing invoice accuracy, customer complaints, third party customer ratings of the utility, outage notification, abandoned call rate standard, and first call resolution, among others. At a high level, these customer-centric metrics aim to ensure that customer needs are met quickly and efficiently. These metrics do, to some extent, reflect the responsiveness of the utility to customer requests.

An example of a responsive metric is Hawaii's **Truck Roll-Related Responsiveness** metric. This measures the average number of business days it takes to complete work related to meter replacements that are within the utilities' control.[106] This is one of the scorecard metrics that is monitored by the utilities under the PBR framework. The utilities have a target of 10 business days or 14 calendar days to complete the work. Currently, there is no reward or penalty for meeting or exceeding the target.

In addition, though not specific to field requests, Massachusetts's **Service Appointments** metric measures the percentage of appointments that are kept as scheduled and reports these results annually. This utility-specific metric compares actual performance results with both the utility's historical and statewide performance. The utility may be penalized for lagging behind historical

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[105] State of Rhode Island and Providence Plantations Public Utilities Commission. *Report and Order*. Docket Nos. 4770 and 4780. August 15, 2018.

[106] Hawaii Public Utilities Commission. *In the Matter of Instituting a Proceeding to Investigate Performance-Based Regulation. Decision and Order No. 37787*. Docket No. 2018-0088. Web. Filed May 17, 2021. <https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21E17B53226E00118>. P. 133.

performance rates, calculated as a regulatorily-set percentage of total annual transmission and distribution revenues.

A supplemental **Customer Satisfaction Surveys** metric, also implemented in the state of Massachusetts, requires the utility to submit the results of two different surveys: a statistically representative residential customer satisfaction survey and a survey of randomly selected customers that have contracted the utility's customer service department. If the utility, which receives a score of between 1 (poorest performance rating) and 7 (highest performance rating), obtains a score of less than 5, it will be liable to pay penalties. An average score of less than 4 will be penalized at the maximum penalty value.[107]

8.3 Storm response PIMs: New York

On December 23, 2013, following Hurricane Irene, Tropical Storm Lee, and Superstorm Sandy, the NYPSC issued an *Order Approving the Scorecard for Use by the Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages (Case 13-E-0140)*. The scorecard is a tracking-only mechanism; the objective was to develop a quantitative tool that the utilities and the NYPSC could apply to assess electric utility performance in restoring electric service during outages resulting from major storms or other outage events. With the scorecard, "deficient utility practices and decision-making can be identified and disincented and excellent utility performance can be recognized and rewarded."[108]

The NYPSC directs each electric utility to provide scorecard data within thirty days of the completion of customer restoration after (a) any outage that lasts for more than three days, (b) any outage defined as a network interruption,[109] or (c) any other outage for which the NYPSC's staff requests such data. Staff uses the data submitted to determine a score for each outage for each utility. The scorecard is intended to be a dynamic and fluid tool, subject to periodic review and improvement. If a particular metric does not serve its intended purpose, the scorecard design can be easily modified on a going-forward basis to ensure that the right measurements are being used.[110]

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[107] Commonwealth of Massachusetts: Department of Public Utilities. *Service Quality Guidelines*. Docket No. 12-120-C, Attachment A. Web. December 22, 2014. <https://archives.lib.state.ma.us/bitstream/handle/2452/724234/ocn987380797.pdf-1?sequence=2&isAllowed=y>.

[108] State of New York Public Service Commission. *Draft Emergency Response Performance Measures*. Case 13-E-0140. December 2013. P.2.

[109] Defined in: State of New York Public Service Commission. *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*. Case 09-E-0428. Issued and Effective March 26, 2010.

[110] State of New York Public Service Commission. *Draft Emergency Response Performance Measures*. Case 13-E-0140. December 2013. P.6.

The scorecard New York adopted assigns metrics and points based on three categories: preparation (150 points), operational response (550 points), and communications (300 points). These categories are intended to capture the key activities associated with major storm events.[111]

Figure 28. New York emergency response performance measures – preparation

Area of Interest	Definition of Measure	Measurement Criteria	Points
Event Anticipation	Complete steps to provide timely and accurate emergency event preparation in response to the National Weather Service or the company's private weather service, in accordance with the company's PSC approved Electric Emergency Plan, for an event expected to impact the company's service territory	Employees/Contractors planning	15
		Press Releases issued / text messages / emails sent	15
		Municipal Conference Calls held and highly effective	20
		Municipal Conference Calls held and effective	10
		Life Support Equipment (LSE) customers alerted	15
		Point of contact for Critical Facilities alerted	15
		Company compliance with Training Program as specified in Commission Approved Emergency Plan	15
		Participation in all pre-event mutual assistance group calls	15
		Verify Materials / Stockpiles level based on forecast. If materials are not on hand, correct situation within 24 hours	40

Source: State of New York Public Service Commission. *Draft Emergency Response Performance Measures*. Case 13-E-0140. December 2013.

The preparation metric focuses on utility activities in anticipation of a significant outage event. Its criteria are used to score a utility for activities and communications prior to forecasted storms

[111] The scorecard differs from New York's two reliability metrics—SAIFI and the Customer Average Interruption Duration Index ("CAIDI")—which establish targets for acceptable performance as part of each utility's Reliability Performance Mechanism ("RPM"). The utility RPM is a part of the utility's rate plan, and the two metrics only measure utility performance in providing reliable electric service during normal conditions on an annual basis. In contrast, the scorecard is a tool to measure utility performance (including preparation and communication activities) after each significant major outage. Source: State of New York Public Service Commission. *Draft Emergency Response Performance Measures*. Case 13-E-0140. December 2013.

and in response to alerts from the public or the utility's weather report.[112] Preparation begins with planning. Effective emergency plans define roles, responsibilities, standard operating procedures, mutual assistance procedures, communications procedures, and training programs. In the days leading up to storm events, the electric utilities begin implementing the guidelines contained in their emergency plans, like closely monitoring weather forecasts and taking other specific preparatory actions.[113] Figure 28 shows performance measures under the preparation metric.

The second metric, operational response, evaluates the utility's performance during both a significant outage event and in the subsequent recovery period until normal service is restored. It aims to evaluate the utility's response and ability to effectively mobilize personnel.[114] Relevant measurement criteria include management of downed wires, damage assessment, crewing, mutual assistance, estimated restoration times, safety, and coordination with municipalities, emergency operations centers, and other utilities (see Figure 29). An important aspect of this metric is accurate and timely Estimated Time of Restoration ("ETR").[115] Additionally, crewing is another dynamic component of outage restoration that assesses whether the utility has secured adequate resources to perform work in the initial stage of restoration; utilities are not penalized for acquiring additional resources if they are released by other utilities.[116]

The third metric—communications—assesses the utility's ability to receive and disseminate information about an outage event and the recovery process. During a storm event, it is important to keep in constant communication with customers, the general public, news and media, and local officials. It is especially critical to disseminate timely and accurate information as widely as possible during an extended power outage. Periodic reports are likewise required to keep the public's expectations in the post-storm period realistic.[117] Important communications aspects of emergency management include informing customers about an impending outage, keeping local authorities informed of damage assessments and estimated restoration times, and informing end users of safety measures and the availability of necessary supplies in a timely manner (see Figure 30).[118]

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[112] Ibid.

[113] Ibid. P. 14-15.

[114] Ibid.

[115] Ibid. P. 5.

[116] Ibid. P. 21.

[117] Ibid. P. 8.

[118] Ibid. P. 23.

Figure 29. New York emergency response performance measures – operational response

Area of Interest	Definition of Measure	Measurement Criteria	Points
Down Wires	Response to downed wires reported by Municipal Emergency Official	< 18 hours (3-5 day restoration) < 36 hours (>5 day restoration)	60
Preliminary Damage Assessment	Completion of preliminary damage assessment	< 24 hours from start of restoration	30
Crewing	80% of the forecast crewing committed to the utility	< 48 hours from the start of restoration	30
Estimated Time of Restoration (Made available by utility on web, Interactive Voice Response, to CSR's, etc)	Publication of Global ETR in accordance with ETR Protocol	Exceeds expectation: < 24 hrs (3-5 day restoration) < 36 hrs (> 5 day restoration)	50
		Meets expectation: < 36 hrs (3-5 day restoration) < 48 hrs (> 5 day restoration)	30
	Publication of Regional/County ETRs in accordance with ETR Protocol	Exceeds expectation: < 24 hrs (regions with 3-5 day restoration) < 36 hrs (regions with > 5 day restoration)	50
		Meets expectation: < 36 hrs (regions with 3-5 day restoration) < 48 hrs (regions with > 5 day restoration)	30
	Publication of Local/ Municipal ETRs in accordance with ETR Protocol	Exceeds expectation: < 36 hrs (3-5 day restoration) < 48 hrs (> 5 day restoration)	50
		Meets expectation: < 48 hrs (3-5 day restoration) < 72 hrs (> 5 day restoration)	30
ETR Accuracy	Global ETR accuracy as published in accordance with ETR requirement time	Accurate within +/- 24 hours	40
	Regional ETR accuracy as published in accordance with ETR requirement time	Accurate within +/- 12 hours (3-5 day restoration) Accurate within +/- 24 hours (> 5 day restoration)	40
	Local ETR accuracy as published in accordance with ETR requirement time	Accurate within +/- 12 hours	40
Municipality Coordination	Coordination w/ Municipalities regarding hazards or electric utility equipment impeding road clearing, down	Execution of Coordination Protocols pursuant to Commission Approved Emergency Plan	20

Source: State of New York Public Service Commission. *Draft Emergency Response Performance Measures*. Case 13-E-0140. December 2013.

Figure 30. New York emergency response performance measures – communications

Area of Interest	Definition of Measure	Measurement Criteria	Points
Call Answer Rates	Customer calls answered by properly staffing call centers	90%+ calls answered within 90 sec.	30
		80% to <90% calls answered within 90 sec.	20
Municipal Calls	Municipal call must be properly managed and provide, at minimum, baseline information, updates on road clearing activities, and allow for Q&A.	Municipal calls held and highly effective	30
		Municipal calls held and effective	20
		Successful implementation of an operator assisted calling system	10
Web Availability	Company's web site must be available around the clock, and must be updated at least hourly, until restoration is complete.	Websites should include the baseline restoration information, all press releases issued during the event, a complete list of safety tips, an outage location map of affected areas, summaries of outages and ETRs by municipality and county, and the locations and times of dry ice distribution.	40
LSE Customers	LSE customer contact	80% affected LSE customers contacted within 12 hours	15
		LSE customers that were unable to be contacted had at least two attempts made within 12 hours	15
		100% affected LSE customers contacted or referred to an emergency services agency within 24 hours	20
PSC Reporting	Provide storm event information to PSC in accordance with Electric Outage Reporting System (EORS) guideline requirements	All reporting on time, including at a minimum information required by existing EORS guidelines	40
Customer Communications	Press releases / text messaging / email / social media	Issue daily messages through the stated communications vehicles for each day of the utility restoration which must include information such as outages, ETRs, contact information, etc.)	60
Outgoing message on telephone line	Recorded message providing callers with outage information is updated within one hour of communication releases.	Message must be updated within an hour of communication releases that is consistent and coincides with the information contained in news releases	20
PSC Complaints	Number of storm/outage related PSC complaints received	≤ 20 per 100,000 customers affected	20
		≤ 40 per 100,000 customers affected	10

Source: State of New York Public Service Commission. *Draft Emergency Response Performance Measures*. Case 13-E-0140. December 2013.

9 Appendix A: PBR and MRP features

9.1 Advantages of PBR over COS

PBR mechanisms have some advantages over COS regulation. PBR mechanisms have been shown to result in ***improved incentives*** with respect to utility performance and can be designed such that they ***drive innovation*** and ***better investment decisions*** on the part of utilities. The PBR approach may reduce administrative burden and regulatory costs (e.g., due to fewer regulatory proceedings) as well as lead to more stable rates for customers.[119] A well-designed multi-year PBR that consists of well-defined mitigation measures can also reduce the utility's regulatory risk, lowering its cost of debt, and ultimately benefiting consumers. Moreover, utilities are ***encouraged to operate more efficiently*** to achieve or surpass regulatorily set productivity targets. PBR can provide strong incentives to increase performance and improve productivity because it allows a utility to derive a significant financial benefit from doing so.[120] This benefit is precisely the incentive that motivates companies in competitive markets to control costs and deliver exceptional service to their customers.

The experiences of jurisdictions that have implemented PBR illustrate the role of this regulatory framework in encouraging productivity improvements. In the case of FortisBC of Canada, the regulator, the British Columbia Utilities Commission ("BCUC"), explained: "the Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements."[121] In the UK, regulator Ofgem stated that the PBR regulatory framework brought benefits to electricity customers for 20 years and has "delivered increased capacity and investment, greater operating efficiency, higher reliability, and lower prices."[122] It added that, "since privatization, allowed revenues have declined by 60% in electricity distribution and 30% in electricity transmission. These reductions have been achieved without sacrificing capital investment, which has continued across all sectors since privatization."[123]

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[119] Rate stability under PBR is a function of the rate-setting formula. Utility rates, typically set under an I-X approach, will only increase by inflation (I) less the productivity factor (X), plus other flow-through mechanisms. This formula applies over multiple years, allowing for a longer-term outlook for utility rates. Source: Olson, Wayne, and Caroline Richards. "It's All in the Incentives: Lessons Learned in Implementing Incentive Ratemaking." *The Electricity Journal* Volume 16, Issue 10 (December 2003): 20-29.

[120] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal* Volume 14, Issue 8 (October 2001).

[121] British Columbia Utilities Commission. *Commission Order G-44-12*. Reasons for Decision. P. 22.

[122] Ofgem. *Regulating Energy Network for the Future: RPI-X@20 Emerging Thinking*. Web. January 20, 2010. <https://www.ofgem.gov.uk/sites/default/files/docs/2010/01/emerging-thinking_0.pdf>. P. 50.

[123] Ibid.

PBR regimes are usually expected to lead to an overall reduction in the regulatory burden mainly because of the lower frequency of regulatory proceedings (when compared with markets under a COS approach) and a less onerous review of costs typically required of the regulator.[124] With respect to the latter point, under COS, regulators spend considerable time and expense to bridge this so-called information gap. In contrast, under PBR, the regulator does not need to know the costs of each O&M item but rather the range of possible costs. This allows the regulator to approve a PBR plan that can elicit maximum efficiency from the utility.[125] For the utilities, reduced regulatory micro-management allows them to respond more quickly to technological and competitive challenges. For customers, this may mean lower prices.

A PBR regime does not necessarily lead to a fall in capital investment. Indeed, capital additions to electric distribution and transmission utilities in Ontario increased by an average of 12% per year between 2005 and 2012. Likewise, a review by Ofgem found that the PBR in the UK has "…served consumers well, delivering lower prices, better quality of service and more than £36bn in network investment since privatization twenty years ago."[126]

9.2 MRP features

9.2.1 Regulatory term

The regulatory term is the number of years of the MRP, or the time between a major review of the underlying components of the rate regime[127] and the subsequent review. For example, CMP proposes a 3-year regulatory term under its MRP.

The length of the regulatory term needs to balance competing pressures. Frequent resets over shorter MRP periods may negatively affect utilities' investment planning. A longer period can increase the motivation for the utility to make cost reductions, as it will be able to retain increased profits over the regulatory term (subject to the terms of an ESM, if one is applied). At the same time, longer periods between resets potentially increase the risk of rate shock because of the increased likelihood of discrepancies between actual and forecast expenditure—a disadvantage to both consumers and utilities. This happens because, over a longer regulatory term, there is greater risk that business circumstances may not turn out as forecast and that targeted productivities cannot be achieved.

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[124] Sappington, David, Johannes Pfeifenberger, Philip Hanser, and Gregory Basheda. "The State of Performance-Based Regulation in the US Electric Utility Industry." *The Electricity Journal* Volume 14, Issue 8 (October 2001).

[125] Comnes, G. Alan, Steven Stoft, Nathanael Green, and Lawrence J. Hill. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues Volume I*. LBL-37577, UC-1320. Web. November 1995. <https://eta-publications.lbl.gov/sites/default/files/report-lbnl-37577.pdf>. P. 6.

[126] Ofgem. *RIIO - a new way to regulate energy networks; Final decision*. Web. October 2010. <https://www.ofgem.gov.uk/sites/default/files/docs/2010/10/decision-doc_0.pdf>. P. 2.

[127] These components may include allowed rate of return, performance standards, etc.

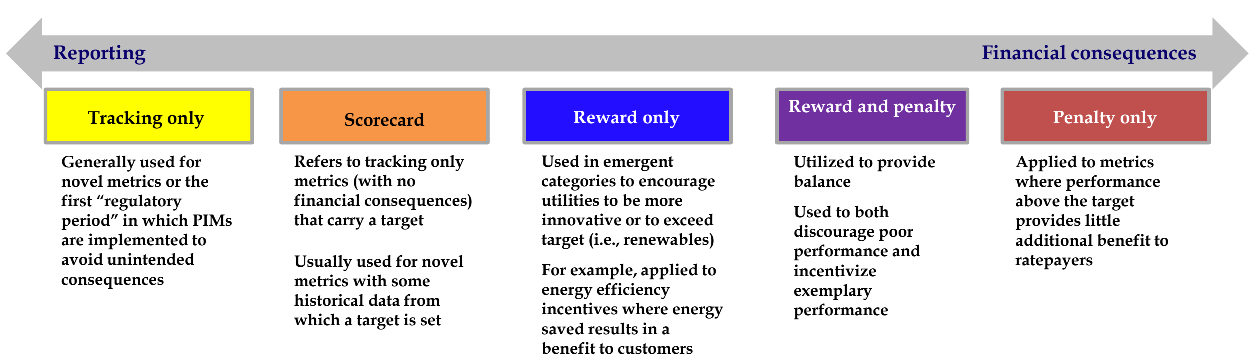
The relative preference for a term may also be affected by the form of attrition relief (for instance, rate cap and annual adjustment mechanism) relative to a utility's capital investment plans; if there is significant uncertainty, especially as it relates to capital investment, a utility may prefer a shorter term to be able to reflect updated capital investment expectations in rates on a timely basis. This is also to the benefit of consumers, as capex can be monitored and rates adjusted as required, including downwards if capital is not spent.

9.2.2 Performance metrics

Performance incentive mechanisms, or simply performance metrics, are regulatory tools that quantify a utility's activities and outcomes. These metrics specifically hone-in on issues that are of high priority or concern to customers. For instance, PIMs will support oversight of the utility in areas in which it has historically performed poorly, or set targets in areas in which the utility is not under the existing regulatory structure incentivized to exceed standards. Quantifiable targets are set for some metrics, with which a utility's reported scores are then compared; the utility may be financially penalized for failing to meet performance expectations, or, on the flip side, entitled to financial rewards if it exceeds its targets. Sometimes, the utility's performance scores are simply tabulated in the form of so-called scorecards and then made publicly available.

Penalty-based metrics tend to be applied to traditional objectives, like resilience, reliability, and customer service. System average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI") are two common reliability metrics. Sample customer service PIMs include, but are not limited to, customer satisfaction, customer complaints, call response times, billing accuracy, and customer survey responses. For emergent goals, or those originating in legislatively or statutorily mandated state objectives, tend to be more rewards-based. Some examples of such emergent metrics include emissions reductions metrics (i.e., achievement of renewable portfolio standards, greenhouse gas emissions reductions, CO_2 reduction from electric vehicles), energy efficiency and demand-side management- ("DSM") related metrics (i.e., peak savings, energy savings from DSM, energy efficiency program participation), electrification of transport (i.e., utility fleet electrification, EV load, EV count, charger installation or sites, off-peak EV charging), or asset investment efficiency or effectiveness (i.e., acquisition of grid services, avoided transmission and distribution investments), to name a few. Figure 31 shows the PIMs spectrum from reporting to having financial consequences.

Figure 31. Structure of PIMs



Performance metrics and the policy and/or regulatory objectives informing their development vary by state. However, there are key overarching principles that guide the PIM design process. Importantly, PIMs are outcome-based, clearly defined, easily interpreted, and time-bound. If designed well, PIMs set explicit goals for the utility to achieve within an unambiguous period of time; the regulator should then be able to determine whether the set goals have been met in a relatively straightforward process where measured outcomes are compared to the targets set in the PIMs development process. There are yet other common design principles for PIMs: they should be consumer-centric, informed by cost-benefit analyses, quantifiable and verifiable, and focus on promoting the achievement of only superior performance (i.e., the targets should not be easily met). PIMs should also only be implemented if they cover activities that fall within the control of utility management; for example, an electric distribution utility, unlike a vertically-integrated utility, does not have control over EV uptake.

PIMs were developed and included in Hawaii's MRP proposal, while in Minnesota and Washington, MRPs were first approved while PIMs (and other PBR elements) were considered in adjacent proceedings.

9.2.3 Trackers and riders

Trackers, as mentioned in Section 5.2.3, are revenue adjustment or accounting mechanisms that include a predefined cost recovery level in the revenue requirement.

To protect consumers, cost trackers are methodically reviewed by the regulator before implementation and are only applied to specific costs. The predefined cost recovery level is then tracked and adjusted for actual costs incurred in subsequent rate reviews, and any additional costs are recovered through tariff sheet provisions called rate riders.

Jurisdictions have different approaches to reconciling any costs above the set tracker level. In some, utilities are expected to bear these costs; in other words, no true-up mechanism is applied. In contrast, other jurisdictions see utilities share costs with customers, while yet others implement a complete true-up mechanism. For underspends, some jurisdictions require the return of these funds to ratepayers.

The benefit of the capital tracker mechanism is the potential streamlining of regulatory proceedings. This occurs when certain categories of costs are pre-determined and not contested or deliberated during subsequent rate reviews. If cost containment is still deemed a concern by the regulator, then the implementation of an MRP (with its reduced number of rate cases) should provide the regulator with extra time to conduct a prudency review of these costs that have been more thoroughly tracked by the utility thanks to the implementation of this mechanism. Moreover, capital trackers may prove to be a more suitable alternative to cap or escalation mechanisms if: there are few or no comparable peer companies from which to determine an appropriate cap or escalation; if the purpose is to replace capital-intensive infrastructure or assets (for which a regulatory review would be required, one way or another); or if the industry is in a state of rapid transition (where historical costs insufficiently reflect present or future costs).

There are several challenges in applying the capital cost tracker mechanism. One is assessing the need for high capex. For example, it may be difficult for a regulator to appraise a proposed accelerated distribution modernization plan as opposed to other causes of capex increases (i.e., capex for new generation or emissions control). Furthermore, a jurisdiction that simultaneously implements escalated attrition relief may find it difficult to justify capital trackers since revenue is already escalated based on the cost of older assets (where these costs decline over time). Lastly, if designed so that utilities recover all capital expenditures in full, capital trackers may lead to weaker performance incentives. Utilities may also request greater capital trackers especially during times of challenging business conditions, and in such case the regulator should consider the impact on performance in granting such request.[128]

9.2.4 Exogenous factor

Standards and criteria for the Z factor are discussed and outlined before the start of the regulatory period. These standards and criteria are expected to guide decision-making after the occurrence of any incident. Specifications at the time of the setting of the formula are often made in the following areas:

- ***Areas considered outside the control of the utility*** - typically, they include but are not limited to (i) changes in regulatory requirements (particularly service standards); (ii) changes in law (such as accounting, tax, and environmental regulations); and (iii) natural disasters.

- ***Financial impact*** - a minimum threshold for consideration for adjustment based on a Z factor is often determined. Such figures have varied widely across jurisdictions.

- ***Company contribution*** - utilities are sometimes required to cover a portion of the costs associated with incidences for which the regulators allow adjustment based on a Z factor. Such amounts, which are considered similar to deductibles in an insurance context, vary widely across jurisdictions with respect to both structure (either fixed or a percentage of total costs associated with incidences) and amount.

The Z factor can either be specific (including enumeration of qualified events) or broader as to include any occurrence that meets pre-established criteria or principles. Figure 32 shows examples of criteria or events used by select jurisdictions.

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[128] Guidehouse. *Electricity Regulation for a Customer-Centric Future; Survey of Alternative Regulatory Mechanisms*. Prepared for Edison Electric Institute (EEI). Q2 2020; Lowry, Mark Newton, Matthew Makos, Jeff Deason, and L. Schwartz. *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*. Web. July 2017. <https://gmlc.doe.gov/sites/default/files/resources/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf>; Littell, David, and Jessica Shipley. *Performance-Based Regulation Options; White Paper for the Michigan Public Service Commission*. The Regulatory Assistance Project. August 2017.

Figure 32. Z factor criteria of events in select jurisdictions

Jurisdiction	Sector	Specified events or criteria?	Z factor eligibility
Australia	Distribution	Specified events	• Regulatory change • Service standard change • Tax change • Terrorism events • Insurer credit risk • Natural disaster, and • Network charge pass through events
British Columbia	Distribution (FortisBC)	Specified events	• BCUC or other regulatory agencies' directives • Acts of legislation or regulation of government • Changes due to Generally Accepted Accounting Principles ("GAAP") • Changes to actuarial evaluations • Force Majeure events; and • Other extraordinary events as agreed to by the parties in the negotiated settlement
California	Distribution	Criteria	• Event causing the cost must be exogenous to the utility • Event must occur after implementation of the PBR • Utility cannot control the costs • Costs are not a normal part of doing business. • Event affects the utility disproportionately. • PBR update rule must not implicitly include the cost • Cost must have a major impact on the utility • Cost impact must be measurable • Utility must incur the cost reasonably
Maine	Distribution (Central Maine Power)	Specified events	• Change in law • Environmental remediation • Extraordinary storms • Capital gains or losses
Ontario	Distribution	Criteria	• Unforeseen events outside of management's control • costs above a certain materiality threshold (0.5% of the total revenue requirement) • Materiality threshold is differentiated on the basis of the relative magnitude of the revenue requirements: for distributors with a revenue requirement below $10 million, the threshold is $50,000 and for distributors whose revenue requirements are above $200 million, the threshold is $1 million

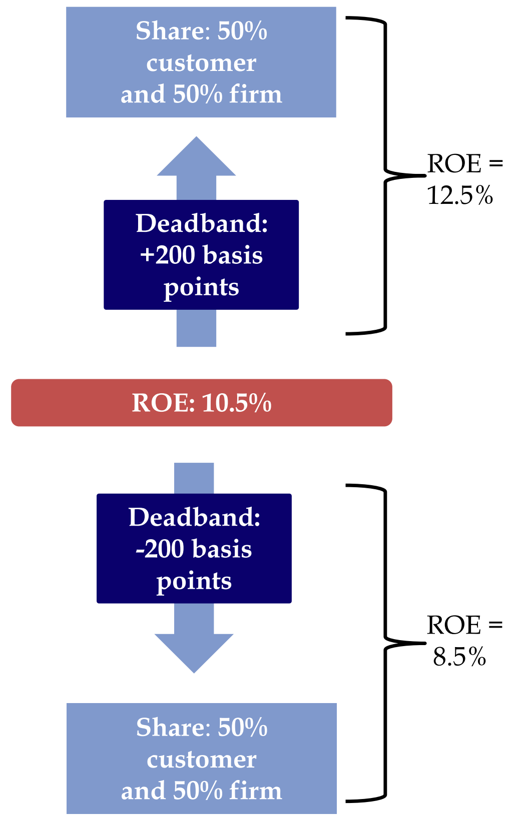
Source: Australian Energy Regulator, British Columbia Utilities Commission, California Public Utilities Commission, Maine Public Utilities Commission, and Ontario Energy Board

9.2.5 Earnings sharing mechanisms

PBR, among other goals, aims to motivate management to improve efficiency by weakening the link between incurred costs and allowed prices. However, earnings above particular thresholds may be politically unacceptable, undermining the acceptability of a PBR framework. An ESM is designed so that the extraordinary earnings (or losses) are shared between the company and its customers rather than retained (or absorbed) entirely by the company if formula-driven price adjustments result in too wide of a divergence between prices and costs.

ESMs involve three elements: a target ROE, a deadband around that ROE in which no sharing takes place, and a sharing of gains or losses outside of the dead-band, as shown in Figure 33. Deadbands and sharing percentages can either be symmetrical or asymmetrical. Under the symmetrical system, customers share both upside and downside risks equally or proportionally with utilities, while under an asymmetrical system, customers or the regulated utility take on a disproportionate portion of the risk.

Figure 33. ESM design elements



Moreover, sharing percentages may be gradated. For instance, customers or utilities may gain a greater proportion of savings or bear a greater proportion of costs as profits increase or decrease. The inclusion of gradated sharing is often determined by considering whether added complexity in the formula outweighs the incentive gained in doing so. Some believe that as efficiencies become more challenging to achieve, firms should be allowed to retain a higher percentage of the savings. Others contend that higher levels of savings can lead to supernormal returns (more than the normal or average returns) for the utilities if these are not disproportionately shared with customers.

However, there are also some identified drawbacks to ESM. First, an ESM can complicate the administration of a PBR system. For instance, ENMAX was concerned with the information and detail requested by intervenors and the regulator during the process of determining the earnings sharing amount. Second, it blunts the efficiency incentives created by shifting to PBR. Some argue that successful PBR implementation does not require an ESM, while others believe that by allowing customers to share in benefits—which arguably would not occur in the absence of incentives—the overall political acceptability of a PBR plan may increase. For instance, true-ups under a symmetrical ESM mechanism can neutralize the perceived impact of rate increases in the re-basing or review stage.

An ESM may also help avoid the possibility of unscheduled regulatory interventions, such as on windfall profits taxes, which distort patterns of investment and returns. While some jurisdictions are not in favor of ESMs—such as Ontario and Alberta because of the two concerns cited above—they are still adopted in other jurisdictions, including in the US.

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11 Appendix C: Introduction to LEI

LEI is a global economic, financial, and strategic advisory professional services firm specializing in energy and infrastructure. The firm combines a detailed understanding of specific network and commodity industries, such as electricity generation, transmission, and distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results. LEI is US-owned and operated.

The firm had its start in the initial round of privatization of electricity, gas, and water companies in the United Kingdom. Since then, LEI has advised regulators, private sector clients, market institutions, and governments on policy initiatives, market and tariff design, asset valuation, market power, policy, and strategy in markets worldwide. LEI maintains primary offices in Boston and Toronto and has consultants in Buenos Aires, Chapel Hill, Hong Kong, Los Angeles, Taipei, and Warsaw.

Figure 34. Selected LEI clients throughout the world

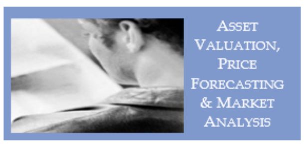
The following attributes make LEI unique:

- ***clear, coherent, and relevant deliverables*** grounded in substantial topical and quantitative evidence;
- ***extensive experience in the New England markets*** providing expert advice to utilities and market players on various market design issues and policies in the energy, capacity, and ancillary service markets;
- ***internally developed proprietary models*** for forecasting electricity energy and capacity market simulation, forecasting of renewable energy credits ("RECs") and contract and asset valuation, incorporating best practices from nonparametric techniques, sophisticated econometrics, game theory, real options techniques, and Monte Carlo;

- ***balance of private sector and government clients*** enables LEI to effectively advise both regarding the impact of regulatory initiatives on private investment, and the extent of possible regulatory responses to individual firm actions;
- ***data-driven empirics***, yielding recommendations that are based on evidence and robust quantitative and qualitative analysis;
- ***wealth of knowledge of energy and infrastructure regulation and regulatory regimes*** worldwide and ***extensive experience with market design***; and
- ***objective and independent staff*** not beholden to any group or sector of the industry.

LEI has a reputation as a provider of thoroughly grounded, independent analysis. LEI is active across the power sector value chain and has a comprehensive understanding of the issues faced by investors, utilities, and regulators alike. LEI's areas of expertise are briefly described below, and include: (i) price forecasting and asset valuation; (ii) regulatory economics, performance-based ratemaking, and market design; (iii) expert testimony and litigation consulting; (iv) transmission and distribution; (v) renewable energy; and (vi) procurement.

Figure 35. LEI's Areas of Expertise



- ► Exhaustive sector knowledge and a suite of state-of-the-art proprietary quantitative modeling tools
  - Wholesale electricity market models
  - Valuation and economic appraisal
  - Due diligence support
  - Cost of capital database
  - Contract configuration matrices

- ► Market design, market power and strategic behavior advisory services
  - Electricity ▪ Natural Gas ▪ Water
- ► Incentive ratemaking
  - Quantify current and achievable efficiency levels for regulated industries
  - Convert findings into efficiency targets mutually acceptable to utilities and regulators

- ► Reliable testimony backed by strong empirical evidence
- ► Expert witness service
  - Material adverse change
  - Materiality ▪ Cost of capital
  - Market power ▪ Tax valuations
  - Contract frustration

- ► Creating detailed market simulations to identify beneficiaries and quantify costs and benefits from proposed transmission lines
  - Valuing transmission
  - Transmission tariff design
  - Procurement process and contract design

- ► Renewable energy policy design, procurement, modeling, and asset valuation
  - Solar, wind, biomass, and small hydro
  - Demand response ▪ Cogeneration
  - Energy efficiency ▪ Micro-grids
  - Emissions credits trading
  - Energy storage technologies

- ► Designing, administering, monitoring, and evaluating competitive procurement processes
  - Auction theory and design
  - Process management
  - Document drafting and stakeholder management

The firm is well qualified to take on this engagement for the following reasons:

- ✓ LEI has ***direct electricity sector experience globally***; the Team will provide insights on best practices observed ***over two decades of experience providing advisory services in the energy industry*** including significant technical, analytical, and advisory experience in all aspects of the energy supply chain in nearly 50 countries worldwide. Our staff has extensive and profound knowledge of the North America and Canada, as well as of Europe, Asia, and the Middle East.

- ✓ LEI staff has ***over twenty years of experience in the Northeast electricity markets*** advising on wholesale market issues, transmission planning, distribution system issues and regulation. LEI has extensive experience in the Northeast US and has worked with both regulators and market participants on a wide variety of deregulated (market) and regulatory issues in New England, as well as evaluation of electricity policy and proposed legislation. Moreover, LEI has ***filed expert testimony in many New England states*** regarding ratemaking, market and regulatory design, and infrastructure investments and the benefits thereof.

- ✓ LEI has ***substantial experience with implementation of PBR and incentive-based regulation both in North America and abroad***. LEI has provided expert evidence and advisory services. LEI has completed quantitative analyses relevant to PBR formula development. LEI has also studied international jurisdictions and crafted detailed case studies for regulators and utilities to consider PBR best practices. LEI has also recommended adjustments that improve the benefits and desired outcomes under PBR.

- ✓ LEI's areas of expertise include, but are not limited to ***retail rate impact analysis, proprietary models for electricity price forecasting and quantitative analysis, renewable energy policy, and cost-benefit and societal impact analysis***. LEI staff is experienced in reviewing market designs and mechanisms; assessing legal and regulatory regimes; estimating the impact of new capacity integration, both conventional and intermittent; performing financial risk management and mitigation analysis; determining the impact of future regulatory trends; and engaging with a large array of stakeholders with differing views in order to develop institutional and regulatory frameworks best suited to evolving contexts.

- ✓ LEI has worked on numerous ***cost allocation engagements and developed tariff frameworks.*** LEI has advised regulatory bodies and utilities in cost allocation projects related to distribution rates, transmission rates, and the revenue requirements of vertically integrated utilities.

- ✓ LEI has designed numerous stakeholder engagements as shown by its ***frequent experience proactively seeking the views of a myriad of stakeholders***. For instance, LEI's work with the Hawaii State Energy Office required reaching out to over one hundred stakeholders on the potential change to utility ownership and regulatory models. LEI conducted a total of 7 community outreach events and 60 one-on-one meetings as well as presented to 3 separate energy conferences. These stakeholders included community groups, large customer users, utilities, government officials, and industry groups.

Finally, LEI prides itself on its pragmatic and ***unbiased outlook, coupled with a creative and quantitative methodology***, understanding that the future can best be understood and shaped through an appreciation of the past and present but with fresh eyes and without any preconceived notions.

11.1 Sample of specific experience related to PBR

LEI has performed a broad range of regulatory services for various utilities around the world, including providing regulatory support pertaining to rate cases, total-factor productivity ("TFP") studies, and benchmarking over the last two decades. Below are some of our relevant qualifications.

- ***Preparation of expert testimony related to PBR:*** LEI was engaged by a distribution facility owner to provide expert evidence and assist in its participation in the Alberta Utilities Commission proceeding to establish parameters for the third PBR term in the province.

- ***Advisor on the first generation PBR development process in Connecticut:*** LEI was retained to support Eversource Energy d/b/a/ Connecticut Light & Power, an electric distribution company in New England, in navigating Connecticut's PBR proceeding. This specifically entails evaluating the PBR design components proposed by the regulator and public stakeholders engaged in the process, assessing gaps in proposed regulatory design, and determining what PBR elements are suitable (or unsuitable) in the context of the state's regulatory and market structures. As part of its scope of work, LEI will also support its client in choosing and/or designing performance incentive mechanisms which will be included in the company's rate filing. As part of this engagement, LEI performs in-depth research of PBR/PIMs across select jurisdictions, provides advisory support in the PBR/PIMs development process, drafts various proposals for public filing, and defends its analysis in both written work and oral stakeholder meetings.
- ***Advised NSTAR Gas on its PBR application in Massachusetts:*** LEI supported NSTAR Gas, a gas distribution company in Massachusetts, in its PBR filing for the 2021-2025 regulatory term. More specifically, LEI performed a TFP study to determine the X factor that will be used for the IBR plan. LEI also conducted a benchmarking study to assess the empirical basis for a consumer dividend. In addition, LEI advised NSTAR Gas on the Gas Systems Enhancement Plan and capital arrangements and discussed the benefits of IBR for consumers. Finally, LEI served as an expert witness on the PBR piece.

- ***Applicability of PBR to Ontario Power Generation ("OPG"):*** LEI was engaged by OPG to support senior management through regulatory processes related to performance-based rates. LEI prepared a discussion paper on incentive regulation mechanisms currently in place in Ontario for electricity and natural gas distribution utilities and presented it at a technical workshop at the Ontario Energy Board. LEI also provided expert testimony regarding the cost of capital and risk factors associated with OPG's prescribed assets and creating a risk-return continuum on which power sector assets could be placed. LEI continues to support OPG as it moves to consider its next generation of rates.

- ***Performance standards setting***: LEI was engaged by the Nova Scotia Utility and Regulatory Board to assist in setting performance standards for Nova Scotia Power in respect of reliability, response to adverse weather conditions, and customer service for Nova Scotia.

- ***Advised on PBR filing and review of the Malaysian electricity regulatory framework:*** LEI was engaged by TNB in Malaysia to work as the project manager of its PBR submission for the 2nd regulatory term. LEI's role in this project includes two phases. In phase 1, LEI's role includes advising on the policy and governance framework for the implementation of IBR, providing strategic advice to IBR Council and TNB management regarding the IBR submission, managing and monitoring the submission process, coordinating with business entities, and attending IBR Council meetings, progress meetings, and challenge workshops. Furthermore, LEI reviewed the current Regulatory Implementation Guidelines ("RIGs") set by the Energy Commission and proposed enhancements to the RIGs. LEI was also in the process of negotiation with the Energy Commission regarding proposed changes to the RIGs. LEI was also responsible for reviewing and enhancing the Revenue Requirement Model, which sets the IBR tariff for each business entity. In addition, LEI was also co-drafting the IBR submission report with TNB and will review the final IBR report before the submission. In phase 2, LEI worked with TNB to negotiate the IBR framework and tariff with Energy Commission.

- ***Literature review on PBR and performance and accountability***: For the Nova Scotia Department of Energy, LEI prepared a comprehensive literature review report covering four key areas: (i) Global experience related to the electricity sector restructuring and liberalization, (ii) PBR – including discussion of various structures of PBR implemented globally and associated challenges, (iii) Performance and Accountability discussing performance monitoring and performance standard measures used in the generation, transmission, and distribution sectors, and (iv) Customer and Service Provider Risks discussing various risks and how these may be impacted or mitigated through the energy market and regulatory structures.

- ***Enbridge Gas Distribution Inc.:*** LEI performed a review and analysis of ratemaking approaches applied to the client's capital expenditure profile, including demonstrating the potential negative impact of "I-X" ratemaking approaches on a utility's ability to earn a fair return. The objective of this engagement will be to demonstrate to stakeholders and the Ontario Energy Board the reasonableness of the revenue cap per customer model that the client has previously relied upon and planned to propose in its next ratemaking review. Furthermore, the secondary objective was to conceptualize the insufficiency of the "I-X" regime, even with a revenue cap per customer model, in consideration of the fair return standard and given the client's business is operating in an environment where substantial capital expenditure needs are projected over the next Incentive Regulation Plan period. [Docket Number EB 2012-0459]
- ***Testimony on PBR:*** LEI provided supporting testimony for FortisAlberta Inc., a Canadian electricity utility, in its filing for a PBR plan. The testimony provided detailed data analysis (including inflation and TFP trends), underpinning of PBR economic theory, and reviews of best practices in various North American and international jurisdictions. The testimony offered backup elements for each of the multiple components of the PBR plan that was proposed by FortisAlberta, Inc. Alberta Utilities Commission, Proceeding: 566]

- ***Formula-based regulation ("FBR") transmission tariff re-opener filing support for an Alberta network service provider:*** LEI prepared a paper to support the ENMAX Power Corporation's transmission FBR re-opener application. In particular, the client wanted LEI to support their argument (i) to amend the G factor calculation to eliminate the G-factor lag effective January 1, 2011, and (ii) reduce EPC's current X-factor of 1.2% to 0.0%. LEI provided support throughout the whole litigation proceeding by responding to information requests that involved additional research and analysis, including synthesizing publications on recent technological advances in the electricity transmission sector and updating the Ontario LDCs TFP model to ten years.

- ***PBR review for Caribbean utility***: LEI was retained by a power utility in the Caribbean to perform an intensive study of the types of PBR employed by regulators worldwide and the implications for key stakeholders, culminating in workshops for the regulator, utility managers, and government representatives. Key issues covered in LEI's analysis included the tradeoffs between using RPI-X style formulations and revenue sharing techniques, accounting for the unique nature of island systems, impacts on employment, and calculation of an appropriate return on equity.

- ***Advised on operating expenditure incentives:*** LEI provided advice to the owner of two Jordanian power distribution companies on the principles behind incentive-based mechanisms for operating expenditure. LEI also provided a detailed analysis of earning sharing mechanisms, sharing savings mechanisms, price cap regulation, and experience in other jurisdictions.

- ***Analysis of IBR components:*** LEI advised the Coalition of Large Distributors in Ontario on third-generation Incentive Regulation Mechanism proceedings of the Ontario Energy Board. The work involved expert testimony filed with the Board with detailed analysis of the theory behind the various components of the IBR system, including inflation and efficiency gains factors and treatment of capital expenditures, among others. The analysis was supplemented with a comparison of actual factors and indices and determined more robust and appropriate indices for Ontario's distribution industry, including total factor productivity analysis for the sector.