MYRP Design for Maine

A framework for encouraging utility cost control, achievement of policy goals, and customer protection

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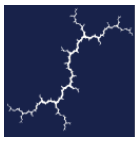

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1. INTRODUCTION

On December 5, 2025, the Maine Public Utilities Commission initiated an inquiry in Docket No. 2025-00354 to develop Commission guidance regarding multi-year rate plans (MYRPs) and performance metrics for investor-owned transmission and distribution utilities. As part of this inquiry, Christensen Associates Energy Consulting (Christensen) and Commission Staff developed a straw proposal (Christensen Report), published on January 20, 2026, followed by a workshop on January 23, 2026. Following this workshop, the Commission directed Christensen to file a report supplement to address issues raised during the workshop and also the applicability of its report recommendations to Versant Power. Christensen filed this supplement on February 2, 2026.

The Commission also provided an opportunity for stakeholders to provide written comments on the straw proposal and supplement by February 9, 2026. Synapse Energy Economics, Inc. (Synapse) was retained by the Office of the Public Advocate (OPA) to provide an alternative proposal for MYRPs and Performance Incentive Mechanisms (PIMs) and respond to certain aspects of the Christensen Report. Synapse's proposal, described below, draws upon Maine's own regulatory experience, as well as our experience with PBR tools across North America.

1.1. Summary of Synapse's MYRP Proposal

Synapse recommends that MYRPs be designed to promote affordability and reliability, while limiting risk to customers. We recommend an MYRP using a revenue cap formula indexed to inflation, with adjustments for productivity. The MYRP should have a term of at least five years in order to encourage the utility to undertake efforts with longer-term cost savings potential.

We recommend that the MYRP framework also include mechanisms to support state energy policy priorities, facilitate accountability, and appropriately balance risks and benefits for the utility. To preserve the utility's cost control incentives, recovery of costs outside of the revenue cap formula should be permitted only for significant and unusual costs that meet specific criteria, including the requirement that such costs support state energy policy goals and do not simply reimburse the utility for business-as-usual needs.

The MYRP should also include an asymmetrical earnings sharing mechanism (ESM) that returns to customers a portion of earnings above an established threshold. This threshold should be large enough to preserve the utility's incentive to control costs. We recommend a threshold of 200 basis points. The risk of significant utility under-earnings should not be addressed by an ESM. Instead, the MYRP framework should include an offramp provision that would terminate the rate plan and trigger a new distribution rate case if the utility's earnings fall 500 basis points below its authorized return on equity (ROE).

To ensure that the Company appropriately prioritizes regulatory and other state policy objectives, the framework should include PIMs, especially PIMs targeting peak load management. With the anticipated continuing growth in electrification, the Company should be incentivized to promote load shifting and load shaping through rate design and other programmatic interventions to minimize the level of grid investment required to support electrification.

Synapse supports maintaining the revenue decoupling mechanism (RDM) to counter the throughput incentive—the utility's incentive to increase sales and disincentive to support load-reducing measures like energy efficiency—and to guard against random fluctuations in earnings caused by year-to-year changes in the weather.

The table below compares Synapse's proposal to Christensen's proposal for specific elements of the MYRP framework.

Table 1. Comparison of Christensen and Synapse Proposals

Element	Christensen Proposal	Synapse Proposal
Framework Type	Price cap (primary recommendation)	Revenue cap
Term Length	4 years	At least 5 years
Attrition Relief Mechanism	Index-based revenues escalated by inflation and productivity	Index-based revenues escalated by inflation and productivity (no position on specific value)
Capital Cost Recovery (F Factor)	Forecast-based F factor for extraordinary capital	Limited supplemental revenues with strict criteria, only if determined necessary
Revenue Decoupling (RDM)	Eliminate current RDM (primary recommendation)	Maintain RDM
Earnings Sharing Mechanism	Symmetrical 50/50 sharing with 100 bps deadband (±) for price cap; symmetrical 50/50 sharing with 300 bps deadband (±) for revenue cap.	Asymmetrical sharing of excess earnings above 200 bps deadband
Off-Ramp Provision	ROE deviation of 500 bps	ROE falls 500 bps below authorized
Exogenous Cost Recovery	Threshold = 0.0013 × operating revenue	Similar approach with strict criteria for storm cost recovery and for treatment of small event costs
Consumer Dividend	40 bps	Agee with inclusion of consumer dividend (no position on specific value)

2. BENEFITS AND RISKS OF MYRPS

In this section, we discuss potential benefits of MYRPs and also note key risks. No approach to ratemaking is failsafe, and MYRPs require special care to ensure that they do not become a financial giveaway to the utility. Thus, we outline critical principles for effective MYRP design.

2.1. Overview of the Potential Benefits and Risks of MYRPs

When designed well, MYRPs can encourage utilities to reduce spending and find cost efficiencies, while providing utilities with additional revenue between rate cases and reducing administrative burden. The Commission recognized the potential benefits of MYRPs relative to traditional cost of service regulation when it approved Central Maine Power's (CMP's) first multi-year rate plan, observing that the MYRP would "force the Company to bear the consequences of poor decisions and will allow it to retain the benefit of good decisions. Ratepayers share in the benefits of improved incentives through the substantial productivity offset that is included in the Stipulation."[1]

Despite the many potential benefits offered by MYRPs, they can also present risks – particularly if not designed well. Poorly designed MYRPs may reduce risk for utilities, allowing for more expeditious cost recovery with less regulatory lag and even reducing scrutiny of investments and exacerbating existing information asymmetries.

The defining feature of an MYRP is that it promotes utility cost control and operational efficiency by severing the link between revenues and spending during the term of the plan. With spending and revenues decoupled, the utility is incentivized to constrain spending to increase earnings. Synapse thus recommends the following design principles for MYRPs:

- Revenues and spending should be decoupled to the maximum extent practicable through the use of an index-based revenue formula rather than forecast-based revenue formula.
- Supplemental capital recovery mechanisms beyond the index should be limited and subject to rigorous oversight and accountability to mitigate the risk of over-investment or imprudent spending.
- The MYRP term should be sufficiently long to allow the utility to pursue (and benefit from) longer-term efficiency gains.
- There should be no reconciliation of actual revenues to actual spending, as such true-ups would materially weaken incentive properties.

[1] Maine Public Utilities Commission. Detailed Opinion and Subsidiary Findings. Docket No. 92-345 (II). January 10, 1995 (hereafter "1995 Order"), p. 37.

- There should be sufficient reporting and monitoring to ensure that the subject utility is fulfilling its obligations to provide safe and reliable service, with metrics and even targeted incentives implemented to ensure that utility actions support policy objectives.

3. BACKGROUND ON MYRPS IN MAINE

Maine has a long history of MYRPs, beginning with the "Alternative Rate Plan" or "ARP" adopted in Docket No. 92-345. The initial ARP arose from concerns regarding CMP's rapidly increasing costs in the early 1990s and that CMP "lacked a corporate culture that was strongly committed to cost cutting."[2] The details of the initial ARP were developed collaboratively by a broad array of stakeholders and presented to the Commission as a stipulation. The Commission adopted the ARP in expectation that it would "provide a 'better means' to ensure that ratepayers do not pay for inefficiency and that management has the proper incentive to control costs."[3]

CMP's initial ARP was established with the following characteristics:

- The ARP was established as a price cap plan, where rates (rather than revenues) were escalated each year using an (I-X) formula.
- The plan had a stay-out period of 5 years, in which CMP agreed to not file another rate case.[4]
- The price index was set based on the annual change in the Gross Domestic Product-Price Index ("GDP-PI"), less a productivity offset ("X").[5]
- The productivity index (the "X" in the formula) was set to approximately 1% in order to allocate a portion of efficiency gains to ratepayers.
- An earnings sharing mechanism was established with a deadband of 350 basis points around CMP's approved ROE. Outside of the deadband, over- or under-earnings were shared 50/50 between shareholders and ratepayers.[6]
- A provision was made to allow certain mandated costs to be accommodated outside of the price index, but those costs must exceed $3 million in annual revenue requirements,

[2] 1995 Order, p. 5.

[3] *Ibid.*

[4] 1995 Order at 36.

[5] 1995 Order at 7.

[6] 1995 Order at 8.

have a "disproportionate effect on the Company or the electric utility industry," and not be otherwise included in the price index.[7]

- The ARP provided for annual reviews to determine the mandated costs that could be passed through to consumers, verify the annual profit-sharing and price-cap rate adjustments, and evaluate the Company's quality of service performance based on customer satisfaction, reliability, and customer service.[8] In addition, the stipulation included a mid-period review designed to allow the Commission to "assess the overall operation and results of the ARP's performance."[9]

CMP operated under successor ARPs for most of the next two decades. In 2013, CMP proposed a new ARP formula. Specifically, CMP proposed that capital investments be based on CMP's forecast of capital costs, which would be subject to reconciliation and a sharing mechanism.[10] The Commission found that CMP's proposal to recover capital costs based on a cost forecast would be inconsistent with the principles of both incentive regulation and cost-of-service ratemaking. In rejecting this approach, the Commission explained that, "By tying CMP's profits to the level of investments, the [capital recovery mechanism] removes one of the core objectives of an ARP, the elimination of the incentive to over-capitalize."[11]

After the Commission rejected CMP's proposal to include a forecast of capital costs in its ARP, CMP proposed a revised approach to incorporate its capital spending forecast into the I–X formula by introducing a K factor, which resulted in a negative productivity (X) factor. The OPA opposed this revision, instead recommending that major capital investments be addressed outside the I–X framework using traditional cost-of-service practices.[12] Ultimately, the Commission approved a stipulation in which CMP withdrew its ARP proposal and returned to cost-of-service regulation, with the option to pursue a single-issue revenue requirement adjustment to recover costs associated with its new billing system.[13]

[7] 1995 Order, at 11.

[8] 1995 Order at 38.

[9] 1995 Order at 25.

[10] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 7.

[11] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 7.

[12] Direct Testimony of Tim Woolf on Behalf of the Maine Office of the Public Advocate. Docket No. 2013-00168. December 12, 2013. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 25, 2014.

[13] Maine Public Utilities Commission. Order Approving Stipulation. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168.

4. RECOMMENDATIONS FOR MYRP DESIGN

4.1. Revenue Cap versus Price Cap Regulation

Recommendation: **Synapse recommends that Maine adopt revenue-cap rate plans and continue its revenue decoupling mechanism. Revenue caps with decoupling true-ups reduce the utility's risk that it will collect less revenue than needed due to fluctuations in weather and also counter utility disincentives to support energy efficiency and other load reducing technologies that are important for achieving Maine's energy policy goals.**

Under traditional ratemaking, the Commission sets base rates in a base rate case, which then remain fixed until the next base rate case. Under this approach, any change in sales between rate cases causes the utility's revenues to increase or decrease, depending on whether actual sales exceed or fall below projections. As a result, revenues are inherently unpredictable. This framework also creates a throughput incentive, encouraging the utility to take actions that increase electricity sales—thereby increasing revenues—while discouraging actions that would reduce sales, such as investments in energy efficiency or distributed generation.

A price cap perpetuates the throughput incentive inherent in traditional ratemaking. While such a framework may encourage the utility to promote electrification, as noted in the Christensen report, it provides no incentive to ensure that incremental electricity consumption occurs in a manner that avoids unnecessary strain on the grid or wasteful usage. Moreover, price caps reduce the utility's willingness to support energy efficiency and other load-reducing technologies, despite the critical role these resources play in achieving Maine's energy policy goals.

Revenue-cap plans largely address this problem by establishing annual allowed revenues, rather than rates, based on expected sales volumes. However, revenue-cap plans alone do not true up actual revenues to allowed revenues, leaving the utility exposed to revenue shortfalls or windfalls resulting from weather variability or other exogenous factors, thereby increasing its risk exposure. The addition of a revenue decoupling mechanism addresses this limitation by implementing a systematic revenue true-up.

Under a revenue decoupling mechanism, the utility recovers its authorized revenue requirement independently of fluctuations in customer electricity consumption. If actual revenues fall short of the authorized amount—for example, due to weather, economic conditions, energy efficiency, or customer-owned generation—the regulator applies a surcharge to customer bills to recover the shortfall. Conversely, if actual revenues exceed the authorized level, customers receive a bill credit. These adjustments are implemented through a transparent, formula-based process, typically on an annual or monthly basis.

Accordingly, Synapse recommends that Maine adopt a revenue-cap MYRP with continuation of a revenue decoupling mechanism to ensure that the utility is financially indifferent to changes in electricity sales resulting from energy efficiency or factors outside of its control.

In its supplemental filing, Christensen maintained its support for a price cap, emphasizing the desirable incentive that a price cap would provide to the subject utility to build infrastructure to support growth in output. Christensen also acknowledged the cost efficiency benefits of a revenue cap but concluded that the price cap approach better suits Maine's current policy environment given the emphasis on electrification.

Synapse does not agree that a price cap is needed to encourage the utility to undertake investments to support electrification by allowing it to retain additional revenues from increased sales. Utility incentives to expand rate base persist even under revenue cap regulation, because the utility's allowed earnings (as set in the next rate base) will be equal to its rate base multiplied by its allowed ROE. Investors in the financial markets evaluate utilities based on earnings and earnings-per-share growth, which is inherently tied to the size of the utility's rate base. Thus, utility management retains a structural incentive to expand rate base, with growth in electricity demand providing a key opportunity to justify such investments. An MYRP can mitigate the incentive to overcapitalize by allowing the utility to retain the benefits of cost savings during the rate plan, but that incentive weakens as the next rate case approaches, since the utility's allowed revenues will be reset to recover prudently incurred new investments.

4.2. Term of the MYRP

Recommendation: **Synapse recommends that Maine adopt an MYRP framework with a stay-out period of at least five years.**

The stay-out period in an MYRP defines the length of time before a utility is allowed to adjust its rates in a rate case. The duration between rate cases can have important impacts on utility cost-control incentives. Typically, MYRPs have stay-out periods of three to five years. When determining the appropriate stay-out period for an MYRP, regulators must balance two competing factors:

- Cost-containment incentives: A longer stay out period improves the ability of utilities to benefit from implementing cost reductions during an MYRP, improving the cost-containment incentives provided by an MYRP.

- Risk: A shorter stay-out period reduces risks to customers by adjusting rates to reflect actual costs more frequently. However it reduces the utility's cost containment incentive, as the utility benefits from cost efficiencies for less time before rates are reset. If there is little certainty regarding whether the MYRP revenue targets are set appropriately, then a shorter stay-out period may be warranted to mitigate this risk.

Uncertainty regarding revenue targets may arise because the revenue targets are set based on cost forecasts that are not sufficiently transparent or well-vetted. If the MYRP is based primarily on well-

vetted and transparent formula, a longer stay-out period is likely appropriate. Given that CMP has filed for distribution rate increases every three years or so over the period 2013-2025 without a broad-based attrition relief mechanism during the intervening years between filings, Synapse recommends an MYRP with a stay-out period of at least five years. We expect that the MYRP's index-based attrition relief mechanism will allow the utility to operate with sufficient revenues for the duration of a five year stay-out period. Indeed, CMP's MYRPs between 1995 and 2013 ranged from five years to seven years, providing another indication that a five-year period would be reasonable.

4.3. Attrition Relief Mechanism

Recommendation: **Synapse recommends that revenues during the MYRP be escalated according to an external index, such as GDP-PI. More sophisticated approaches (such as a separate index for labor costs) could also be considered.**

Attrition relief mechanisms (ARMs) escalate a utility's allowed revenues over the course of an MYRP. The ARM can be based on either an external price index or a utility cost forecast. Synapse recommends using an external price index to escalate revenues during the MYRP. Synapse does not support Christensen's recommended forecast-based approach (F-Factor), as forecasts are difficult to vet and pose excessive risk for ratepayers.

A principle objective of MYRP design is to break the link between a utility's revenues and spending, at least for the term of the MYRP, to encourage the utility to reduce costs in order to increase its profits. Index-based approaches are preferable to cost forecasts or historical spending patterns, because indexes provide attrition relief based on external factors rather than the utility's own spending behavior and revenue needs. The use of utility cost forecasts should generally be avoided due to the utility's incentive to over-capitalize and information asymmetry between regulators and the utility.

An ARM based on forecasts increases revenue by pre-determined amounts in each plan-year based, at least in part, on a utility's cost projections. The percentages can be different in each year, or the total increase can be levelized across the years. ARMs based on cost forecasts enable the utility's revenues to accommodate unusual investment trajectories, such as a capital investment surge. Since the ARM generally operates as a cap on revenues, it provides an incentive for the utility to ensure that actual investment costs are kept under the cost cap. While this incentive to keep costs below the revenue cap provides some limited cost containment incentives, forecast-based ARMs shift risk onto ratepayers. This is because forecasts exacerbate information asymmetries since the utility will always have the more technical knowledge and information regarding its systems than regulators and other stakeholders. This makes it challenging to ensure that cost forecasts are reasonable, and places customers at risk that the allowed MYRP revenues will be set too high. Because regulators and any intervening parties can never completely vet the accuracy of cost forecasts, utilities have an inherent bias to overstate their costs and understate revenues.

Given the many shortcomings and potential risks associated with forecast-based MYRPs, Synapse recommends an ARM with revenues indexed to inflation and productivity. While there are different

price series that may be used for inflation indexing with the ARM, the gross domestic product price index (GDP-PI) that is published by the Bureau of Economic Analysis (BEA) is uncontroversial. Christensen recommends a more complex composite approach, with the use of separate indices for labor and material cost escalation. Synapse is not averse to this approach.

4.4. Supplemental Revenues

Recommendation: **Synapse recommends that supplemental revenue mechanisms be used with caution and limited to exceptional types of investments that meet specific criteria. Such mechanisms should also be accompanied by additional reporting requirements.**

Utilities often advocate for an additional mechanism to provide supplemental revenues above an MYRP's typical revenue- or price-cap formula. When making these arguments, utilities frequently claim that they are operating in a period of inordinately high costs or significant investment needs — citing electrification, resilience, and other concerns to explain why revenue increases allowed by the ARM are insufficient. Although the reasons for supplemental capital can be compelling, these mechanisms may attenuate the utility's incentive to control costs if not designed carefully. They may even create a self-fulfilling prophecy: the existence of a mechanism for increased capital spending might itself enable greater-than-needed spending, especially where utilities are already operating with an incentive to seek new capital investment opportunities to increase earnings (i.e., capex bias). As the Maine Public Utilities Commission observed in 1993, "A reason for not treating capital expenditures separately is that it would help eliminate the oft-discussed problem of [rate of return] regulation giving firms an incentive to overcapitalize (the so-called "Averch-Johnson effect"). As an additional reason, by incorporating all capital expenditures for each category of resource … into the price cap formula, the company would have an incentive to make least-cost investment decisions."[14]

As a general matter, supplemental revenues should only be provided for those investments that have not already been funded through the ARM. This means that business-as-usual costs, including normal replacements of aging infrastructure, substation projects, and other routine investments should not be funded through a supplemental revenue mechanism.

There are several key factors to consider when evaluating whether to include a supplemental revenue mechanism in an MYRP. First, it is critical to assess whether implementing an MYRP without any supplemental funding mechanism would result in unacceptably low levels of utility investment over the term of the plan. This assessment should be holistic, considering all manner of costs and savings. For example, savings achieved during the MYRP (including savings on O&M) and retained by the utility could potentially be used to fund incremental capital needs, reducing the need for supplemental revenues.

[14] Maine Public Utilities Commission. Order of Partial Dismissal. In: *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014"),* Docket 2013-00168. August 2, 2013, at 3.

If a supplemental revenue mechanism is deemed necessary, then it is worth considering whether approving an MYRP that includes a supplemental funding mechanism is preferable to pursuing traditional cost-of-service ratemaking with more frequent rate cases. Since supplemental revenue mechanisms tend to attenuate cost control incentives in the MYRP, the key question is how to design the mechanism to best preserve cost-control incentives.

In particular, the threshold question is how to define eligibility for supplemental recovery. The categories of costs that qualify should be narrowly circumscribed, objectively specified, and clearly distinguished from costs intended to be recovered through the ARM. Absent disciplined and explicit eligibility criteria, supplemental mechanisms risk expanding over time to encompass routine or forecastable expenditures, thereby undermining the incentive properties of the MYRP.

To mitigate incentive issues from supplemental revenue support, Synapse recommends an approach similar to Hawaii's Exceptional Project Recovery Mechanism (EPRM). This mechanism is explicitly intended to generate revenue support for projects placed into service during the term of the MYRP for which cost recovery is not provided through the ARM or incentive mechanisms. Per the EPRM guidelines, "the electric utility bears the burden of proof that all project costs proposed for EPRM treatment meet the criteria specified herein and are not routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business as usual investments."[15] Further, the EPRM rules require offsets for all known and measurable net savings or benefits resulting from all eligible projects.[16] The utility must submit a business case study "identifying and quantifying all operational and financial impacts of the Eligible Project and illustrating the cost/benefit tradeoffs that justify proceeding with the project to the extent that such impacts can reasonably be determined." Only those projects that are prudent and reasonable, provide customer value, and enhance the affordability of energy services are eligible for recovery through the ERPM.[17]

4.5. Exogenous or Mandated Costs

Recommendation: **Synapse recommends that the criteria for qualifying for exogenous costs recovery should be stringent, with a materiality threshold no lower than that established in CMP's initial MYRP. We do not support aggregation of low cost events that would not qualify on their own for exogenous cost recovery. Our recommendations for storm cost treatment are provided in the next section.**

The Christensen report proposes a Z factor for certain types of exogenous costs, including costs associated with storms, policy changes, *force majeure*, and other causes. Christensen recommends that

[15] Hawaii Public Utilities Commission. Docket No. 2018-0088. Decision and Order No. 37507. December 23, 2020. Attachment A at 9.

[16] *Id.*

[17] Ibid at 9-10.

eligible costs be limited to costs that are unforecastable at the beginning of the MYRP term, uncontrollable by the utility, and above a materiality threshold equal to the product of 0.0013 and CMP's operating revenue (i.e., 13 basis points of CMP's operating revenue). However, Christensen recommends that this threshold apply to the sum of exogenous events.

Synapse generally agrees with the criteria for exogenous cost treatment; i.e., that qualifying costs be limited to those that are unforecastable, outside of the control of the utility, and exceed a threshold for significance. We do not take a position on the specific value of the materiality threshold but note that it should not be lower in real terms than the materiality threshold established in the Company's initial MYRP (i.e., $3 million in 1995 dollars). Synapse further recommends that the same criteria be applied to cost saving events—for example, tax cuts or accounting changes that benefit the utility—to flow these unexpected and unearned windfalls to ratepayers.

We do not support Christensen's proposal to allow aggregation of costs to meet the materiality threshold. It is unclear how commonly the sum of small events (i.e., events not qualifying on an individual basis for Z factor relief) would exceed the Z factor threshold, but the proposed aggregation approach could mean that it would be relatively easy for CMP to be made whole for small events. In such a case, what would the point even be of establishing a Z factor cost threshold?

4.6. Storm Costs

Recommendation: Synapse recommends that a five-year average of storm expenses be embedded in base rates, and that only those storms exceeding a much higher materiality threshold and also meeting severity criteria qualify for Z factor recovery (or accounting order).

Under Christensen's proposal for storm cost recovery, it appears almost certain that the sum of storm recovery costs would exceed the Z factor materiality threshold, based on recent history. While individual storms are not forecastable at the start of the MYRP, the aggregate impact of these storms may be reasonably estimated in advance and provisioned for through base rates. We recommend that base rates include an allowance for storm cost recovery based on a five-year average of storm costs. Only those storms exceeding a much higher materiality threshold and also meeting severity criteria should be eligible for Z factor recovery (or accounting order). The specific parameters of the storm cost recovery mechanism, including cost sharing and specific threshold criteria, can be evaluated in each rate case.

4.7. Earnings Sharing

Recommendation: **Synapse recommends adoption of an asymmetrical ESM (i.e., sharing over-earnings only) with a deadband of 200+ basis points to preserve utility incentives to achieve cost efficiencies.**

The primary purpose of an earnings sharing mechanism (ESM) is to ensure that utility earnings do not become excessive during MYRPs. The vast majority of these ESMs are one-way adjustments that cap the potential over-earning of the utility and require that the utility share some of its over-earnings with

customers. ESMs typically include a deadband (or neutral zone) around the authorized ROE in which the Company does not share over- or under-earnings.

Although ESMs reduce risks to customers, they also reduce the utility's incentive to control costs, since they limit the upside potential to the utility. Under an MYRP, the utility's most direct means of increasing earnings is to reduce its costs, but an ESM requires that the utility return some or all of these cost savings above a certain threshold to customers.

In approving an ESM with a 350 basis point deadband in 1995, the Commission stated that "a wide bandwidth [deadband] provides: 1) a "safety net" that protects the Company and ratepayers from the increased risks associated with extreme swings in earnings; 2) further benefits to ratepayers if CMP is able to achieve significantly improved profitability; 3) a way to shift the risks of low profitability away from ratepayers; and 4) improved incentives and risk allocation."[18]

The Christensen report proposes a symmetrical ESM with 50/50 sharing of over- and under-earnings outside of a 100-basis-point deadband (i.e., the authorized ROE plus or minus 100 basis points). Synapse does not support the use of a symmetrical ESM. The utility should not be made whole for under-earnings, since this would unduly transfer business risk from the Company to its customers. This concern is amplified under a revenue-cap framework, where the utility is already insulated from sales volatility associated with weather, energy efficiency, distributed generation, and macroeconomic conditions, and where additional mechanisms may provide recovery for exogenous or storm-related costs.

Shareholders—not ratepayers—should bear the consequences of imprudent management decisions or ineffective cost control that reduce achieved earnings. Extreme under-earnings are better addressed through offramps (discussed below). Synapse instead recommends an asymmetrical, upside-only ESM with a greater deadband to encourage the utility to seek efficiencies and contain costs. Provisionally, we recommend an asymmetrical ESM with a deadband of 200 basis points above the allowed ROE to ensure that the utility is incentivized to pursue cost efficiencies through the potential to earn more than its allowed ROE.

4.8. Offramps

Recommendation: **Synapse recommends an offramp that would be triggered if CMP's earnings were to fall 500 basis points below the utility's authorized ROE. This will protect the utility from extreme under-earnings without excessively insulating the utility from the impacts of poor management.**

Without sharing of under-earnings, the utility is financially accountable for poor performance. That accountability, however, should not extend to cases of extreme under-earning, where the utility's financial viability is truly at risk. MYRPs are typically structured with offramps that permit termination of the rate plan and initiation of a new rate case in the event that utility earnings fall far below the

[18] 1995 Order, p. 9.

authorized ROE. Synapse agrees with the recommendation in the Christensen report that an offramp be triggered if the utility's earnings were to fall 500 basis points below the utility's authorized ROE.

4.9. Consumer Dividend

Recommendation: Synapse supports inclusion of a consumer dividend with the MRYP.

Synapse supports inclusion of a consumer divided (S Factor) within the ARM. At this point, Synapse does not take a position on the appropriate value for the consumer dividend.

4.10. Annual Reporting and MYRP Modifications

Recommendation: **Synapse recommends that the Commission establish clear reporting requirements and a process for annual review. Additionally, the Commission should address which elements of the MYRP plan may be modified during the plan term and set conditions and process for any such modifications.**

The MYRP should not be a "set it and forget it" framework. Synapse recommends that the Commission establish clear reporting requirements. Specifically, the subject utility should be required to file an annual report with performance metrics and key financial indicators each year. Following the filing of the annual report, there should be a formal review process with scope for intervenor participation to evaluate utility performance and assess whether modifications to the MYRP framework are warranted.

Annual reporting should include a structured set of metrics that allow the Commission and stakeholders to monitor both operational performance and spending trends throughout the MYRP term. The purpose of this reporting is not to facilitate *ex post* cost reconciliation, but rather to provide visibility into whether the utility is maintaining core asset management programs and service quality while operating under the MYRP. In addition to the utility's existing service quality metrics addressing reliability (e.g., SAIDI, SAIFI, CAIDI, and major event day reporting) and customer service performance, we recommend that the utility report operational and capital deployment indicators. Such metrics could include:

- **Vegetation management:** total miles trimmed, cycle compliance rates, backlog levels, and program expenditures relative to plan assumptions.
- **Pole inspection and asset condition programs:** number of poles inspected, rejected, and replaced; inspection cycle compliance; and related spending.
- **Storm activity and restoration costs:** number of declared storm events, restoration cost totals, cost per event, and comparison to historical averages.
- **Capital investment:** annual capital expenditures by major category (e.g., reliability, resilience, asset replacement, new business, grid modernization), and year-end rate base balances.
- **Operations and maintenance (O&M) spending:** total O&M and major subcategories relative to baseline levels or index assumptions.

Systematic reporting of these indicators would allow the Commission to identify troubling trends—such as deferred maintenance, vegetation backlog growth, or abnormal capital surges—early in the plan term. The data provided through annual reports should also be useful to assessing the efficacy of the MYRP plan at the end of the term, and should inform modifications to the plan and to the utility's revenue requirement (i.e., rebasing) for the next MYRP period.

There should be a high bar for modifying an MYRP during the term of the rate plan, since doing so could undermine the incentive power of the plan by undermining regulatory certainty. as mid-course adjustments can weaken its incentive properties by eroding regulatory commitment and creating expectations of ex post cost recovery. In general, unforeseen and material exogenous events should be addressed through a properly designed Z factor, while extreme and sustained under-earnings should be addressed through predefined offramps. Mid-term modifications should therefore be limited to narrow circumstances, such as correcting structural or mathematical errors in the plan (e.g., double-counting in the revenue formula or mis-specified index parameters), or addressing performance incentive mechanisms (PIMs) that are demonstrably unworkable due to data limitations or design flaws not reasonably foreseeable at the time of approval.

To preserve incentive integrity, the Commission should establish clear procedural rules and objective standards governing MYRP modifications, including: (1) which plan elements are eligible for modification; (2) any quantitative or materiality-based triggers; and (3) the evidentiary and procedural requirements for initiating and approving changes.

4.11. Going-In Rates and Rebasing

Recommendation: **Synapse recommends that going-in rates be set using a historical test year with known and measurable adjustments. At the conclusion of an MYRP, rates should be reset to reflect actual costs, with potential adjustments to ensure the utility does not game the process by concentrating spending in the historical test year.**

While the Christensen report does not address how to set going-in rates or rebasing, we recommend that this be explicitly considered when establishing an MYRP framework. Although it may not be necessary to predetermine the exact mechanics of the next rate case, the MYRP should be structured to mitigate incentives for intertemporal cost shifting. In particular, absent safeguards, a utility could defer discretionary expenditures during the early years of the plan and accelerate spending in the final year in order to inflate the test year revenue requirement for the subsequent MYRP. To reduce this risk, the Commission could adopt an approach that normalizes rebasing inputs using a historical cost trend rather than relying exclusively on a single, end-of-term test year. This is similar to the method currently employed in Alberta, where rebasing is informed by a multi-year historical average (or trend-adjusted historical costs) rather than the final year alone. By grounding rebasing in observed cost trajectories over several years, this approach reduces the incentive to concentrate spending in the final year(s) of the plan and better aligns rates with sustainable cost levels. Designing the rebasing framework in this manner helps preserve the incentive properties of the MYRP while protecting customers from rate volatility associated with strategic timing of expenditures.

4.12. Performance Incentive Mechanisms (PIMs)

Recommendation: **Synapse recommends that an MYRP be accompanied by a set of performance incentive mechanisms to safeguard against degradation of service and to encourage more efficient use of the grid.**

PIMs can help to align a utility's financial incentives with the public interest. Maine already has numerous service quality indicators (SQIs) in place, and these should be retained. New PIMs could be developed, particularly for encouraging the utility to pursue reductions in peak demand, which is critical to ensuring that electrification does not result in unnecessary grid expansion.

When designing PIMs, regulators should ensure that incentive structures promote measurable improvements in utility performance while protecting customers from unnecessary costs. Financial incentives and penalties should also be significant enough to influence utility behavior while still protecting customers from excessive rate impacts. PIMs should be designed in concert with cost recovery mechanisms. For example, if the utility can recover the costs of meeting a PIM target through a tracker, then it has every incentive to spend as much as required to meet the PIM target, even if the costs outweigh the benefits. Thus, the ARM must contain strong cost containment incentives. In addition, the total value of potential PIM rewards plus the utility's base return on equity should not be excessive, or the utility will have a stronger incentive to expand its rate base.

We recommend the following principles for PIM design:

1) PIMs should be structured around clearly defined policy objectives or goals such as improving reliability, advancing affordability, or supporting beneficial electrification.

2) Targets should focus on outcomes that provide tangible value to customers.

3) PIMs must be objective, quantifiable and supported by reliable and verifiable data, and largely within the utility's control. PIMs should rely on credible and well-supported baselines, which may be derived from historical performance, benchmarking, or forward-looking policy goals.

4) Transparent methodologies for calculating performance incentive metrics are important to ensuring accountability and preventing the risk of gaming.

Synapse specifically recommends that Maine adopt one or more PIMs with a specific focus on peak load reduction to support its future electrification goals. Several states have recently implemented PIMs with a similar focus.

Table 2 below provides examples of PIMs from other jurisdictions specifically designed to reduce peak demand and provide benefits to both customers and the electric system. Each of these PIMs is either currently in effect or has been in effect in recent years.

Table 2. Performance Incentive Metrics

Utility, State, Docket	PIM	Description	Performance Incentive
Commonwealth Edison (IL) Docket No. 22-0067	Peak Load Reduction (2024-2027)	This PIM targets weather-normalized peak load reductions (in megawatts) that provide value in the PJM capacity market. The utility is expected to achieve load reductions by leveraging its existing demand response portfolio (including direct load control, time-of-use load reductions, and solar and energy efficiency programs).	The incentive is symmetrical, (reward or penalty) of +/- 6 basis points. Rewards apply to load reductions of 60+ MW above a baseline. Penalties apply for achieving fewer than 50 MW of load reductions above the baseline.
National Grid (NY)	Locational System Relief Value ("LSRV") Load Factor ("LLF") EAM- (2021-2024)	The LLF EAM is designed to improve the load factor of more constrained portions of the distribution system. Performance is measured by the number of LLF substation sites that maintain or improve their load factor each year.	The incentive is upside-only and structured as an adjustment to the utility's return on equity (ROE), measured in basis points.
Duke Energy Carolina (NC)	Time Differentiated and Dynamic Rate Enrollment PIM- (2024-2026)	This PIM encourages the utility to develop and expand the use of time-varying rates to help address peak load growth. Performance is measured by incremental annual customers enrolled in the Company's dynamic and time-differentiated rates.	The incentive is upside-only and is structured as a fixed dollar amount awarded when predefined performance targets are met.

Source: Rocky Mountain Institute. PIMs Database. Available at: https://pims.rmi.org/

Christensen recommends Maine adopt an AMI Utilization PIM similar to what has been implemented by the Hawaiian Electric Companies.[19] The AMI Utilization PIM would encourage improvements in customer usage management and reward CMP for enrolling customers in programs that leverage AMI-enabled price signals. Under this approach, CMP would receive incentives for enrolling customers in demand response programs, time-of-use rates, or other programs that provide price-based incentives to reduce usage during peak periods. The proposed incentive design would reward CMP based on the measured reduction in peak demand attributable to customers enrolled in AMI-enabled programs. CMP would first estimate the dollar value of reducing peak load (dollars per KW of peak load reduction) using factors such as avoided ISO-NE Regional Network Service costs, reduced capital investment needs, and

[19] Christensen Associates, *"Proposed Approach to the Indexed Regulation of Maine's Electricity Distribution Utilities For The Maine Public Utilities Commission"* January 19, 2026

potential greenhouse gas reductions. CMP would then estimate the incremental peak demand reduction associated with enrolling additional customers in AMI utilization programs, using class-specific econometric analysis. However, Christensen note that customers would need to be educated and incented to reduce peak to result in a substantial reward for the Company. The incentive would be calculated by multiplying the value of peak reduction by the estimated per-customer impact and applied annually based on new customer enrollments. The proposal also notes the need to avoid double counting by ensuring that any incentive payments account for administrative costs already recovered through base rates.

Rather than tying financial incentives to customer enrollment in AMI-enabled programs, Synapse recommends that load reduction PIM targets verified peak load reductions. Incentives should be designed to only reward demonstrable reductions in system peak demand within CMP's control, measured in megawatts, to better align CMP's financial rewards with tangible system benefits and consumer value. PIMs must also account for the unique role played by Efficiency Maine Trust (EMT) to reduce peak loads by excluding anticipated reductions attributable to EMT's programs from any peak reductions credited to CMP. The value of peak load reductions should be determined through avoided capacity market costs, including savings from ISO-NE's capacity market, as well as other avoided system costs where appropriate. CMP's incentive would then be calculated using a shared savings framework, under which CMP would receive a defined share of the verified capacity-related cost savings attributable to its AMI-enabled demand reduction efforts. This approach would reduce the risk of overcompensation and double counting, ensure that incentives reflect actual customer behavior rather than program enrollment alone, and strengthen the link between utility performance and outcomes that lower long-term system costs. It would also encourage CMP to pair AMI-enabled rates and programs with effective customer education, engagement, and operational strategies that deliver sustained peak demand reductions.

4.13. Reconciliation Mechanisms

Recommendation: **Synapse strongly recommends against including reconciliation mechanisms in an MYRP, as these eviscerate the utility's cost control incentives.**

Allowing a utility to reconcile spending in excess of the allowed MYRP revenue requirement undermines any cost-containment incentive. When reconciliations are used, the MYRP resembles more of a broad-based cost tracker and loses its ability to encourage cost efficiencies.

5. CONCLUSION

Maine has decades of experience with MYRPs, and that record demonstrates both the potential value of MYRPs and the importance of careful design. When structured appropriately, MYRPs can strengthen incentives for cost control, reduce administrative burden, and provide rate stability. However, MYRPs are not failsafe: if they rely heavily on forecasts, provide broad supplemental revenue mechanisms, or allow reconciliation of spending, they can erode incentive properties and become a pathway for reduced scrutiny and increased customer risk.

Synapse's proposal is intended to preserve the core incentive benefits of MYRPs while ensuring affordability, reliability, and accountability. Specifically, Synapse recommends that the Commission adopt a revenue-cap MYRP indexed to inflation with a productivity offset, with a stay-out period of at least five years. Consistent with Maine's policy goals, Synapse also recommends continuation of the revenue decoupling mechanism to counter the throughput incentive and reduce earnings volatility due to weather and other sales fluctuations. To protect customers while preserving utility incentives, Synapse recommends that cost recovery outside the ARM be limited to narrowly defined, material, and truly exceptional costs—with storm costs largely provisioned for through a historical average and only extreme events eligible for Z-factor treatment under strict criteria.

To ensure that customers share in exceptional utility performance without insulating the utility from ordinary business risk, Synapse recommends an asymmetrical, upside-only ESM with a deadband of 200 basis points or more, coupled with a 500-basis-point downside earnings offramp to address rare circumstances where financial integrity could be impaired. Finally, Synapse recommends that the MYRP be accompanied by targeted PIMs, particularly those designed to encourage verified peak demand reductions and load management, which are essential to ensuring that electrification proceeds in a manner that minimizes long-term system costs. Robust annual reporting and a clear, high-bar standard for limited mid-term modifications are also essential to preserve regulatory commitment while ensuring transparency and responsiveness.

Taken together, these recommendations provide the Commission with a practical MYRP framework that builds on Maine's regulatory experience, reduces risk of over-capitalization and cost pass-through, and better aligns utility financial incentives with the outcomes most important to Maine customers: safe and reliable service, affordability, and efficient integration of electrification and other state energy policy goals.