STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY

Docket No. 26-05-10

APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY D/B/A EVERSOURCE ENERGY TO AMEND ITS RATE SCHEDULES

DIRECT TESTIMONY OF

Gennelle Wilson and Oliver Tully

ROCKY MOUNTAIN INSTITUTE

On Behalf of

The Office of Consumer Counsel

OCTOBER 21, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please introduce the Rocky Mountain Institute ("RMI") panel.

A. The RMI panel is comprised of Gennelle Wilson and Oliver Tully.

Q. Mrs. Wilson, please state your name, role, employer, and business address.

My name is Gennelle Wilson. I am a Manager within the Electricity team at RMI, located at 2490 Junction Place, Suite 200, Boulder, CO 80301.

Q. Mr. Tully, please state your name, role, employer and business address.

A. My name is Oliver Tully. I am a Manager within the Electricity team at RMI, located at 17 State Street, 25th Floor, Unit 2500, New York, NY 10004.

Q. Please describe RMI.

A. RMI, founded as Rocky Mountain Institute in 1982, is an independent, nonpartisan 501(c)(3) nonprofit that is focused on transforming global energy systems through market-driven solutions to secure a prosperous, resilient, clean energy future for all. In collaboration with businesses, policymakers, funders, communities, and other partners, RMI drives investment to scale clean energy solutions, reduce energy waste, and boost access to affordable clean energy in ways that enhance security, strengthen the economy, and improve people's livelihoods.

RMI is active in over 50 countries. RMI's Electricity team works with and for a wide range of partners and clients, including public utility commissions, consumer advocates, and environmental advocates to support electric utility regulatory reforms on topics including

resource and distribution planning, ratemaking and cost recovery mechanism design, performance-based regulation (PBR), and safeguard programs for vulnerable customers.

Q. Mrs. Wilson, please summarize your education and professional experience.

A. I graduated from North Carolina State University with a Bachelor of Arts degree in 2013. In 2020, I graduated from Duke University with a Master of Environmental Management. I have seven years of experience in the field of electric utility regulation. At RMI, I have worked extensively on issues related to utility regulatory reforms to support utility cost discipline, including the design and implementation of PBR tools, as well as non-PBR reforms, such as cost tracker reforms. In my tenure at RMI, I have provided support to several Public Utility Commissions ("PUC"s) on the design, implementation, and evaluation of performance-based regulatory ("PBR") frameworks, including Hawaii, Washington, and Oregon. I have also provided support to stakeholders and intervenors in PBR-related proceedings in North Carolina, Ohio, Virginia, Indiana, and Massachusetts. At RMI, I manage the Performance Incentive Mechanisms ("PIM"s) Database, a publicly accessible repository of information on the design of emergent PIMs across the United States and utility performance. I have also contributed to several reports immediately relevant to the topics we discuss, including A Strategic Framework for Utility Cost Control, Fixing Multiyear Rate Plans (a report RMI co-authored with Synapse Energy Economics), and A Smarter Approach to Cost Trackers, to name a few.

Prior to my tenure at RMI, I was employed as an energy policy researcher and analyst by non-profit organizations focused on energy economics and policy, including the Nicholas

Institute for Environmental Policy Solutions at Duke University, and Southern Environmental Law Center.

Q. Mrs. Wilson, have you previously testified before the Public Utilities Regulatory Authority ("PURA" or "the Authority") or elsewhere on regulatory matters?

A. I was a contributor to an RMI analysis submitted alongside testimony in the first Duke Energy Carbon Plan proceeding before the North Carolina Utilities Commission in Docket No. E-100, SUB 179 in 2022. I have testified on the design of multiyear rate plans and performance incentive mechanisms before the North Carolina Utilities Commission in Docket No. E-7 Sub 1276 in 2023. This is my first time testifying before the Authority.

Q. Mr. Tully, please summarize your education and professional experience.

A. I graduated from the University of California, Berkeley with a Bachelor of Arts degree in 2013. In 2020, I graduated from the Yale University School of the Environment with a Master of Environmental Management. I have nine years of work experience in the field of energy policy and electric utility regulation. At RMI, I work on issues related to regulatory reforms to support customer affordability and utility cost control, including fuel cost management, cost tracker reform, and PBR. I have contributed to several reports immediately relevant to the topics we discuss in this Testimony, including *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals* and *A Smarter Approach to Cost Trackers.* Prior to RMI, I was director of the utility innovation initiative at Acadia Center, where I intervened in proceedings at PUCs throughout New England on issues related to electric utility business model reform, energy burden and affordability, rate design, and Performance-Based Regulation. I was

previously employed as a senior associate at the Energy Foundation, where I provided philanthropic support to groups working to advance utility regulatory reform.

Q. Mr. Tully, have you previously testified before PURA or elsewhere on regulatory matters?

A. No, I have not.

Q. On whose behalf are you testifying in this case?

A. We are testifying in this case on behalf of the Office of Consumer Counsel.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the Company's Performance-based Multiyear Rate Plan ("PBMRP"), identify the deviations between their proposal and what was developed to date in the several-years of PBR proceedings in Docket Numbers 21-05-15RE01, RE02, and RE03, explain the shortcomings of the Company's proposed PBMRP relative to industry best practice and a consumer-protective framework, outline concerns related to the approach to storm cost recovery, and to offer recommendations to the Authority regarding the Company's proposal.

Q. What topics does your testimony address and how is your testimony structured?

A. Our testimony is organized as follows:

a. In Section II, we provide a summary of our conclusions and recommendations.

b. In Section III, we evaluate Eversource's proposed PBMRP and discuss the concerns it, in tandem with the proposed Targeted System Performance ("TSP") Plan,

presents for cost containment and customer affordability. This discussion includes an analysis of the process used by the Company and its consultant to conduct the Total Factor Productivity ("TFP") study, as well as reflections on the management audit. We then offer recommendations to address those concerns.

c. In Section IV, we evaluate the Company's proposal for a Performance Evaluation System, explain its shortcomings relative to stakeholder deliberations and input in Docket No. 21-05-15RE02, and offer recommendations to address those shortcomings.

d. In Section V, we evaluate the Company's proposed Storm Cost Recovery framework, explain our concerns with the proposal from a cost-containment perspective, and offer recommendations to address those concerns.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your high-level concerns to PURA as described further in your testimony.

A. The Company's proposal is inconsistent with the several years of stakeholder deliberations in Docket Nos. 21-05-15RE01, RE02, and RE03 ("PBR reopeners"), flawed in several respects, insufficient in providing appropriate incentives that will result in efficiencies, imposes too great a risk on customers of incurring unnecessary costs, and impractical for implementation. As such, approval of the Company's PBMRP would be premature and against the interest of Eversource customers. Table A summarizes our high-level concerns with the Company's proposal.

Table A. Summary of Our Concerns with the Company's Proposal

The Company's Proposal is Inconsistent …	• Inconsistent with industry best practices in designing multi-year rate plans (MRP) with revenue adjustment mechanisms to support utility cost containment • Inconsistent with OCC's recommendations in Docket No. 21-05-15RE01 • Inconsistent with the Proposed Final Decision in Docket No. 21-05-15RE01 • Premature in light of the absence of a Final Decision in Docket No. 21-05-15RE01
Flawed …	• Creates an incentive to inflate capital forecasts and drive up capital investment during the plan • Provides fully compensatory revenue for capital additions under a projected cap with minimal regulatory lag and without meaningful cost control incentives • Incentivizes capitalization of operational expense • Is not based on a transparent and analytically rigorous integrated distribution system plan ("IDSP") • Is insufficiently informed by stakeholder deliberations and PURA's guidance on the appropriate design of a Performance Evaluation System
Insufficient …	• Does not provide sufficient incentives for the Company to control costs • Exacerbates, rather than addresses, the perverse incentives of capital expenditure (capex) bias
Impractical …	• Will further complicate and create additional complexity in the annual PBR adjustment process

Q. Please summarize your high-level recommendations to PURA as described further in your testimony.

A. We recommend that the Authority deny the Company's multi-year PBMRP proposal and only approve a one-year rate plan with performance evaluation system in this docket.

We recommend that the Authority continue to establish and finalize generic PBR guidance outside of the instant rate case, so that any subsequent EDC rate amendment applications can be informed by the Authority's guidance and input from the associated stakeholder process and would also allow for greater consistency between EDC rate amendment

applications. In particular, finalizing the IDSP framework so that Eversource can embark on this critical component to formulate a more consumer-protective multi-year framework is critically important.

We recommend the completion of a thorough and comprehensive IDSP process before evaluating and approving the multiyear PBMRP framework and the projected capital additions and forecasted capital investment as proposed by the Company.

We recommend that the Authority establish performance metrics, scorecards, and Performance Incentive Mechanisms ("PIMs") in the one-year rate plan in this docket in order to lay the foundation for a full PBMRP framework while the other components are developed as needed.

We recommend that the Authority use the Performance Evaluation System outlined in the Docket No. 21-05-15RE02 Proposed Final Decision ("PFD") in 2026 as the baseline for establishing PIMs, Metrics, and Scorecards in this proceeding and require material departures from that framework to be clearly justified.

We recommend that the Authority adopt financial incentives only where the record demonstrates that the measure rewards exemplary performance and discourages substandard performance, and that the potential rewards and penalties are appropriately calibrated to the performance objective and customer benefit.

We recommend that the Authority retain the full suite of Metrics and Scorecards included in the RE02 PFD as the baseline reporting framework, including measures that provide

valuable transparency even where outcomes are not exclusively within the Company's control, and carry forward the publicly accessible PBR dashboard contemplated in the RE02 PFD.

III. PERFORMANCE-BASED MULTI-YEAR RATE PLAN (PBMRP)

Q. What is the purpose of this section?

A. The purpose of this section is to describe our concerns with the Company's PBMRP proposal, the TFP study, the TSP Plan, and the management audit. We then articulate our recommendations to the Authority.

Q. What is your recommendation to PURA regarding Eversource's application for a PBMRP in this proceeding?

A. We recommend that the Authority deny the Company's multi-year PBMRP proposal.

As of the date of the submission of this testimony, the Authority has issued no Final Decisions in the PBR reopeners. The intent of Docket No. 21-05-15 and its reopeners is to transition from "traditional 'cost-of-service' regulation to a 'performance-based' regulation (PBR)" by "adopting a framework (PBR framework)".[1] The PBR framework and the associated Revenue Adjustment Mechanisms are intended to "be employed to implement PBR in any future EDC rate case" and constitute a series of well-considered concepts, models, and guidance that will facilitate future implementation of PBR.[2] Further, the "PBR Framework provides both a lens through which to examine an [Electric Distribution Company's (EDC)] rate amendment application and a toolbox of vetted ideas to advance PBR."[3] We recognize that there is no requirement that the PBR reopener docket final decisions be issued prior to the Authority reviewing and approving a PBMRP

[1] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (page 1).
[2] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (page 1).
[3] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (page 1).

proposal. However, the Company's proposal is flawed in several respects and inconsistent with industry best practices in designing performance-based regulation and multi-year rate plans ("MRP") to support utility cost containment – and diverges significantly from the PBR framework developed through years of stakeholder engagement. As such, we recommend that the Authority deny the Company's PBMRP proposal and only approve a one-year rate plan in this docket. The Authority can still set performance metrics, scorecards and PIMs in a one-year rate plan in this docket, laying the foundation for a full PBMRP framework while the other components are developed as needed.

We also recommend that the Authority continue to establish PBR guidance outside of the instant rate case, so that any subsequent EDC rate amendment applications can be informed by the Authority's guidance and input from the associated stakeholder process and would also allow for greater consistency between EDC rate amendment applications. In particular, finalizing the IDSP framework so that Eversource can embark on this critical component to formulate a more consumer-protective multi-year framework is critically important.

Q. Please provide a summary of all your concerns with the Company's PBMRP application.

A. The Company's proposal is inconsistent with industry best practices in designing MRP with revenue adjustment mechanisms to support utility cost containment and is inconsistent with OCC's recommendations and the Proposed Final Decision in Docket No. 21-05-15RE01. The Company's proposal is insufficient in providing appropriate cost-efficiency

incentives. As a result, the Company's proposal will not create meaningful incentives for the Company to manage its spending cost-efficiently.

The Company's PBMRP Proposal, in particular the different treatment of recovery for O&M and capital and the Company's proposed capital funding mechanism, will exacerbate capex bias and weaken incentives for cost containment. The process to determine the Company's proposed X-Factor was not conducted in a sufficiently transparent and inclusive way. The lack of off-ramps in the Company's proposed PBMRP will eliminate a key safeguard against unintended outcomes. And the lack of detail, transparency, and stakeholder input that went into the Company's TSP Plan and the Company's proposed capital investment plan makes it insufficient for adequately evaluating the capital forecast compared to a full Integrated Distribution System Planning process. This creates increased risk for customers in the context of an MRP.

In addition, the implementation requirements for the Company's proposal are impractical, and the Company's proposal to conduct prudence reviews at the same time as the annual reconciliation process will further complicate and create additional complexity in the annual PBR adjustment process.

Q. How is the Company's proposal inconsistent with OCC's positions and other stakeholder input, and the Proposed Final Decision in Docket No. 21-05-15RE01?

A. The Company's proposal is inconsistent with the Docket No. 21-05-15RE01 PFD and misaligned with stakeholder deliberations in that docket in several ways. The Proposed Final Decision in Docket No. 21-05-15RE01 was the culmination of several years' worth

of stakeholder input and participation. While there is no Final Decision in Docket No. 21-05-15RE01, the positions of participants and the PFD provide a useful guide for evaluating the Company's PBMRP proposal, as they reflect several years of stakeholder engagement on the framework and helpful data points and perspectives.

One of the most problematic deviations in the Company's proposal relative to the RE01 PFD is the proposed application of an externally-indexed revenue cap that is only applied to revenue requirements *associated with O&M and not applied to capital* (i.e., a *partially* externally-indexed revenue cap).[4] By contrast, the PFD includes an externally-indexed revenue cap that is applied to *both O&M and capital*. In the Company's proposal, each of the components of the Revenue Adjustment Mechanism (i.e., the Z-Factor, I-Factor, X-Factor, and S-Factor) applies to O&M, rather than to both O&M and capital, as envisioned in the RE01 PFD. We describe further inconsistencies and deviations between the Company's proposal and the RE01 PFD as they relate to each of these factors in more detail in Table B.

Table B. Comparison of the Proposed Final Decision in Docket No. 21-05-15RE01 to the Company's PBMRP Proposal

Mechanism	*RE01 Proposed Final Decision*	*Company PBMRP Proposal*
Revenue Cap / I-X	Externally-indexed revenue cap applies to O&M and capital	Partially externally-indexed revenue cap applies only to O&M; capital lies entirely outside the revenue cap and is recovered through F-Factor

[4] Please note that in this Testimony, we use the term "partially externally-indexed revenue cap" to describe the Company's proposal in which the revenue cap is applied to O&M alone.

Mechanism	*RE01 Proposed Final Decision*	*Company PBMRP Proposal*
I-Factor	Based on the most recent four quarters of Gross Domestic Product Price Index ("GDP-PI"), commencing from the end of the four quarters used for either Going-in Rates (in the case of the first annual I-Factor adjustment) or the most recent I-Factor reset (in the case of Rate Years 2 through 4)	Based on a composite O&M input price index consisting of the Employment Cost Index ("ECI") and GDP-PI, weighted using the industry's labor and non-labor OM&A cost shares. Includes a floor of 0 percent (i.e., the I-Factor cannot go negative) and a cap of 5 percent
X-Factor	To be determined as part of the Total Factor Productivity (TFP) Study submitted in the EDC rate amendment application. Authority has discretion to set X-Factor based on the evidence in the rate amendment proceeding, including setting the X-Factor at zero	The X-Factor of –0.03% is based on the OM&A partial factor productivity (PFP) result of an industry TFP study conducted by the Company's consultant
S-Factor/Customer Dividend	Performance-based S-Factor; illustrative 0–60 basis points (bps) tied to benchmarking	Minimum of 30 basis points and adjusts annually depending on O&M cost performance per customer, relative to inflation-adjusted benchmark. Adjusted +10 bps if O&M cost per customer is below benchmark, −5 bps if above benchmark
Z-Factor	0.75% materiality threshold	0.5% materiality threshold
Capital Funding	CT-Bar used to recover only incremental capital project costs outside of the Revenue Cap formula	F-Factor: capital cost recovery mechanism based on a fixed annual capital investment level for each year of the PBMRP
Return on capital investment in capital recovery mechanism	CT-Bar does not include return/carrying cost until prudence/used-and-useful review	F-Factor includes return on capital investment
Cost of removal	Excluded from CT-Bar	Includes cost of removal in capital revenue requirement
Off-ramps	Four off-ramps related to financial condition, windfall profits, falling interest rates, and excess storm costs	Excluded

As described in more detail later in this Testimony, the Company's proposed capital funding mechanism differs meaningfully from what the Authority had included in the Docket No. 21-05-15RE01 PFD. The Company's proposal includes an F-Factor as a Revenue Adjustment Mechanism for recovery of all capital additions in the MRP. This is a significant departure from the CT-Bar mechanism, as proposed in the RE01 PFD, which was intended as a capital funding mechanism to enable recovery only of incremental capital project costs outside of the revenue cap formula. The proposed F-Factor capital forecasts are not based on an IDSP, as envisioned in the Docket 21-05-15RE03 PFD. Broadly speaking, the checks and balances that were included in the proposed CT-Bar calculation are excluded from the Company's proposal, making the F-Factor resemble the Electric System Improvements tracker that is now statutorily prohibited.

The Docket No. 21-05-15RE01 PFD proposed that the final X-Factor value would be determined in each EDC's rate amendment proceeding. Nevertheless, the PFD established guidelines for how the TFP study should be conducted (described in more detail farther below in this Section). The process to determine the Company's proposed productivity factor was not conducted in a transparent and inclusive way as the Authority envisioned in the Docket No. 21-05-15RE01 PFD.

The Company's proposal does not include any off-ramps, which eliminates a key mechanism that can safeguard against extraordinary events or unintended outcomes.

Q. Beyond the fact that what the Company has proposed is inconsistent with RE01 PFD, what concerns do you have with the partially externally-indexed revenue cap?

A. We are concerned that the separation of O&M and capital as part of the proposed partially externally-indexed revenue cap will exacerbate capex bias and does not adequately strengthen incentives for the Company to contain costs.

The existence of capex bias was recognized by numerous stakeholders and the Authority in the Docket No. 21-05-15RE01 Proposed Final Decision.[5] Capex bias refers to the incentives inherent in the traditional cost-of-service revenue requirement framework, which attaches a profit opportunity to capital expenditures but not to operating expenditures (opex).[6] Under this model, utilities have incentives to increase capital expenses to earn higher returns. In its RE01 PFD, the Authority explains that leveling the playing field between opex and capex can help to "mitigate the 'capex bias,' which posits that investor-owned utilities focus more on capital solutions over operating solutions because the utilities can earn a return on capital expenditures, but not operating

[5] *See* the Authority's discussion of Totex ratemaking: Docket 21-05-15RE01, Proposed Final Decision (July 14, 2025), page 56.

[6] The Authority also discussed the existence of capex bias in its 21-05-15 Phase 1 Final Decision: *Moreover, any assertion that a capital bias does not exist is counterintuitive on several levels. First, both EDCs, as publicly traded companies, have a fiduciary duty to shareholders. If an EDC's internal decision-making process and/or leadership did not select a capital solution that would allow for a return on that investment over an operations-based solution that has no return, all else being equal, the EDC would not be fulfilling its fiduciary obligation (i.e., shareholders will be better off if the EDC selects the capital solution). Second, a capital bias is simply the rational decision-making process from the EDC's perspective under the current regulatory framework. Stated another way, a rational actor definitionally selects the option that provides it, the EDC, with the greatest net benefit. Again, all else being equal, the rational EDC actor should always select a capital solution over an operations-based solution, as it would be in the company's own self-interest given that one provides a return and the other does not. If an EDC does not have a capital bias, then the EDC's decision-making process is not rational, which raises concerns about the efficiency of its other expenses and the overall management and operations of the company. Lastly, asserting that a capital bias does not exist is paramount to claiming that financial incentives are irrelevant to EDCs; this would mean that EDCs are indifferent to the level at which their return on equity is set, which we know is not true.* (Page 29)

expenditures. The utility preference for capex could limit consideration and selection of opex alternatives even if the opex choice would save money for customers."[7]

The Company's own Testimony, Exhibit CLP-IAP-4, included a report from Lawrence Berkeley National Laboratory ("LBNL") that states, "There is evidence that utility ROEs [returns on equity] are higher than financial theory suggests are necessary, resulting in a bias towards CapEx over potentially cheaper OpEx solutions, which could lead to higher electricity rates."[8] We agree with LBNL's assessment.

We believe that the Company's proposal is at odds with the Authority's original purpose when it initiated Docket No. 21-05-15RE01 "to investigate rate mechanisms, including, but not limited to, MRPs, ESM, RDM, and potential measures that better equalize capital expenditure solutions with operating expense solutions."[9]

We are concerned that the exclusion of capital spending from an externally-indexed revenue cap as part of the Company's proposed PBMRP will exacerbate capex bias and weaken the Company's incentives to contain capital costs. While a multiyear rate plan with an externally indexed attrition relief mechanism that applies to both capex and opex in general can help to mitigate capex bias, the Company's bifurcated proposal to apply the indexed revenue cap only to O&M does not adequately do so.

[7] Docket 21-05-15RE01, Proposed Final Decision (July 14, 2025), pages 55-56.
[8] Exhibit CLP-IAP-4, page 8 of 73.
[9] Docket 21-05-15RE01, Proposed Final Decision (July 14. 2025), page 2.

Because the Company's proposed partially externally-indexed revenue cap is applied exclusively to O&M expenses, while capital is forecasted outside of the indexed revenue formula and receives separate recovery through an F-Factor based on a fixed annual capital investment forecast, the proposed framework does not adequately strengthen cost containment incentives for the Company (a more in-depth explanation of this appears later in this Section). We are concerned that different treatment of recovery for O&M and capital creates inconsistent incentives across utility spending and creates a strong incentive for the Company to shift O&M expenses into capitalized costs.

Q. How does the Company's F-Factor proposal compare to the CT-Bar deliberated in RE01?

A. A summary of the key differences between the F-Factor, proposed by the Company in the present proceeding, and the CT-Bar that was included in the RE01 PFD, is provided in Table C.[10] Please note: the table below is included for reference and comparative purposes; we do not endorse the CT-Bar as it is currently proposed in the RE01 PFD.

[10] The OCC did not support the CT-Bar as envisioned in the RE01 PFD. As noted in the RE01 PFD:

OCC expressed the need for several clarifications regarding the design of the CT-Bar in relation to other mechanisms (i.e., the TFP Study) or with certain calculation methodology steps (i.e., Steps 4 and 5). OCC 2025 Comments, pp. 12-13. OCC also expressed concerns with the use of a four-year historical capex spending average in Step 1 and the use of a multi-year capex forecast to determine the incremental amount within Step 2, as these approaches introduce the risk of gaming. Id., pp. 13-14. Additionally, OCC requested clarity on the timing of IDSP decisions in relation to the CT-Bar determinations and expressed concerns regarding the disallowance of carrying charges as this could create an incentive to shift capital projects to become used and useful as a rate case approaches (i.e., the final year of the MRP). Id., p. 14. Finally, OCC shared its support for the Authority's framework regarding capital cost trackers and their use for discrete, extraordinary cost recovery purposes. Id., p. 15. Overall, OCC recommends a case-by-case application-based process, rather than a predetermined CT-Bar budget for the MRP where the capital additions are based on the IDSP. OCC Brief, p. 2. In general, OCC is concerned that the CT-Bar as proposed in the Revised Straw Proposal does not provide sufficient cost control incentives. Id. (RE01 PFD, pages 31-32).

Table C. Summary of Differences Between CT-Bar[11] and Company's Proposed F-Factor[12]

	CT-Bar	*Eversource's Proposed F-Factor*
Planning Venue	Primarily, but not entirely, based on an EDC's planned capital investments from the EDC's latest IDSP	Primarily based on forecasted capital investments included in the TSP, *not* informed by an IDSP
Costs recovered	Certain incremental rate year capital expense (i.e., depreciation and taxes) that the EDC would not ordinarily be permitted to obtain until the next rate case and prudence review	Provides incremental revenues for *all* planned capital expenditures
Return on capital investment	No incremental revenues for return on investment until completion of prudence review	Return on investment included in annual incremental revenues, prior to prudence determination
Reconciliation	Downward only reconciliation for both shortfalls of capital additions placed in service for a given rate year, and capital additions that are later deemed to be imprudent in the next rate case.	Annual downward-only reconciliation to the lesser of: • the total revenue requirement for forecasted capital, or • the total revenue requirement for the actual plant in service
Annual adjustment	Separate annual adjustment for the change in authorized depreciation resulting from the revenue cap formula (i.e., the actual amount of capital additions, as quantified by the CT-Bar, will be reduced by an adjustment for already-recognized depreciation expense.)	MRP capital additions are accounted for on an incremental basis without adjustment for already-recognized depreciation expense in going-in rates.
Prudence review	Subsequent rate case	Requires annual prudence reviews to recover all capital expense
Eligible costs	Capital Plan additions[13] and a historical average of non-Capital Plan additions.[14]	Capital investments in aggregate

[11] As described in Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025, pp.31-40
[12] Exhibit CLP-ELP-1, OCC-857 and OCC-859.
[13]Capital Plan additions were intended to be inclusive of grid planning costs as detailed within the IDSP, and other foreseeable capital additions such as fleet, facilities, information technology, customer service investments, etc.
[14] Non-Capital Plan additions were those that are necessary, yet unforeseeable, and as such were to be based on historical unplanned capital additions limited to exogenous activity such as unforeseeable storm additions. Non-capital Plan additions would require detailed accounting of underlying activity and would be subject to prudency review of the historical costs.

	CT-Bar	*Eversource's Proposed F-Factor*
Non-eligible costs	Cost of removal is not included[15]	Cost of removal is included
Subjectivity to revenue cap formula	Not subject to the X-Factor or total factor productivity study, nor the S-Factor, or the I-Factor	Same as CT-Bar

The most notable and impactful differences between the F-Factor and what was envisioned in the RE01 PFD are: 1) the removal of all capital recovery from the revenue cap formula, such that all capital is forecasted and recovered through a separate F-Factor, and 2) the annual recovery of all incremental annual capital plant addition costs, including return on capital investment and cost of removal, which would be reviewed for prudence annually during the MRP term.

Under the CT-Bar, a portion of capital expenditures represented in the test year would be subject to the Revenue Cap Formula, which would escalate subject to actual changes in inflation (I-Factor) minus productivity (X-Factor) and customer dividend (S-Factor). The CT-Bar would allow supplemental revenues equal to a certain rate year capital expense (i.e., depreciation and taxes) to support *incremental* capital plant additions made by the utility during the MRP term. Under the CT-Bar, the amount of incremental plant additions for which supplemental revenue would be provided would be reduced to recognize revenue already recovered as depreciation expense. Return on capital investment and cost of removal would not be allowed for recovery until the subsequent general rate case, after a

[15] PURA's logic for not allowing the cost of removal is that it would be inconsistent with the decision to exclude carrying charges, neither of which would be appropriate until a prudency determination made in a subsequent rate case proceeding. See Docket No. 21-05-15RE01, Proposed Final Decision, p. 35.

complete prudence review of all capital projects placed into service during the previous MRP.

In contrast, with the Company's F-Factor approach, all capital expense is forecasted. Revenues would be set at the outset of the PBMRP to recover all forecasted capital plant additions, including capital costs and cost of removal, and would be reconciled annually based on actual plant additions deemed prudent.

These differences are significant in that they (i) almost completely eliminate the incentive for cost-efficiency during the multi-year term, and (ii) create additional administrative burden that multi-year rate plans are intended to reduce by requiring an annual prudence review process.

Q. How does the Company's proposed F-Factor weaken the incentive for cost-efficiency relative to best practice MRP design?

A. Relative to best practice MRP design, the Company's proposed F-Factor would weaken the strength of the cost containment incentive that is desired in a well-designed MRP in several ways, including:

a. an incentive to inflate the capital forecast to minimize risk of overspend;

b. the annual reconciliation process creates an incentive to spend up to the F-Factor allowance;

c. proposal to review actual capital spending in excess of the approved F-Factor forecast;

d. no incentive to substitute capex investments for operational solutions;

e. an incentive to capitalize operational expenses; and

f. allowing return on capital investment to be recovered prior to prudence review.

First, all planned capital costs would be reconciled if unspent. Reconciliation creates a strong incentive for the utility to inflate its forecast at the start of the MRP term, and then during the MRP to pursue all planned capital investments up to the forecasted amount. An inflated forecast creates a buffer for the utility to operate within in later years to reduce the likelihood of insufficient revenues to support capital additions, recognizing that no method of predicting the future is accurate. Even if later information, subsequent analyses, or technological developments occur that indicate that there are cheaper alternatives relative to what was forecasted, the Company would not benefit from spending less than the forecasted amount. As a result, the Company would derive no benefit from capital cost efficiencies. In other words, the F-Factor perpetuates the capex-bias and gold-plating incentive associated with traditional cost of service regulation.

The only incentive the Company has to be cost-disciplined in its capital investments during the PBMRP results from the treatment of costs that exceed the forecasted amount. Because the utility would be eligible to recover the lesser amount between either forecasted or actual capital additions, the utility would have an incentive not to exceed the annual forecasted capital addition amount. However, even this incentive is eroded by the Company's proposal that all capital additions in excess of the annual forecasted amount could be deferred and considered for recovery in the subsequent rate case.

Additionally, because OM&A would be subject to the indexed revenue cap, the Company would have a strong incentive to identify operational cost-efficiencies. Accordingly, the utility would be highly reticent to substitute a planned capital project with an operational expense (e.g., a non-wires alternative project) because doing so would increase its operational expense and decrease its potential earnings margin from any OM&A efficiencies it had achieved. Moreover, such a substitution would also likely contribute to a reconciliation of the F-Factor that would reduce the Company's earnings in the form of return on capital investment.

The recovery of all incremental capital plant through the F-Factor, and the separate treatment of O&M subject to the revenue cap, would create a strong incentive for the Company to capitalize operational expense. At worst, the partially externally-indexed revenue cap formula could create incentives to reduce or double-recover O&M expenses. Broadly speaking, implementation of capital projects would result in incremental increases in revenue, whereas marginal O&M expenses would not do so to the same degree.

Finally, because the return on capital investment is included in the forecasted F-Factor costs, the regulatory lag on return on capital investment – which would create a cost containment incentive and be consistent with PURA's decision on storm cost carrying charges in Docket 25-12-13 – would be eliminated.[16] The F-Factor approach would allow

[16] In OCC's Letter in Lieu of Exceptions in RE01, the OCC expressed a similar concern with the CT-Bar as outlined in PURA's Proposed Final Decision. The OCC stated, "We have repeatedly expressed our concerns with the CT-Bar (and the K-Bar before it) for its lack of clear cost containment incentives. We recognize that the proposed lag on the cost of capital proposed in the PFD serves as the only cost containment element of the mechanism. As we have noted throughout this proceeding, we view regulatory lag as an appropriate tool to balance ratepayer and investor interests

return on capital investment to be recovered from ratepayers prior to a prudence review, which is highly unorthodox. As noted by the OCC in RE01, "EDCs have no legal entitlement to recover the return on capital additions before they enter service."[17] The Company's proposal has the potential to set an undesirable precedent for allowing unchecked cost recovery.

In contrast, best practice multiyear rate plans break the linkage between actual costs and revenues during the stay-out period. Multiyear rate plans that are associated with the strongest incentive for cost-discipline apply an externally indexed revenue cap (also known as an attrition relief mechanism) to all costs, including capital and O&M.[18] Capital costs are not forecasted, and opportunities for supplemental capital recovery are limited and determined on a case-by-case basis.[19]

Q. Please elaborate on your concern with the Company's proposal that actual capital spending in excess of the forecasted amount approved in this proceeding be reviewed in a later rate case and prudency review process?

A. The F-Factor, as discussed above, creates an incentive for the utility to inflate its capital forecast. In a scenario in which the actual capital costs associated with a project are likely to be greater than the forecasted amount, this would create a strong incentive for the utility

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and to incentivize cost containment and prudent investment, and we view the structure of the CT-Bar in the PFD as an attempt to subject portions of capital recovery to regulatory lag in order to maintain that balance. Without it, there is risk that the CT-Bar could effectively be an approved general capital budget that will be filled to and above the maximum level with no inherent incentive to control costs in real time." (see pages 6-7). We note that the F-actor approach is similarly subject to the same critique.

[17] Docket No. 21-05-15RE01 OCC Letter in Lieu of Exceptions, page 7.

[18] Gennelle Wilson, Melissa Whited, Courtney Lane, Ben Havumaki, and Cara Goldenberg, *Fixing Multiyear Rate Plans: Building a Firm Foundation for Cost Control,* RMI and Synapse Energy Economics, 2025.

[19] This is consistent with OCC's arguments and recommendations made in RE01.

to seek out cost-effective alternatives to the planned capital investment. The absence of a guarantee that the next rate case will provide an opportunity to recover excess costs is necessary to motivate the utility to operate and invest in a cost-disciplined manner during the multiyear rate plan.

However, if the utility is allowed an opportunity to defer costs incurred in excess of the forecasted amount, as is proposed by the Company, it provides a pathway to double down on capital investment rather than to look for cost-effective alternatives. The assurance that costs in excess of the planned capital forecast can be deferred and reviewed for potential recovery in the next rate case alleviates the pressure to be cost-disciplined during the multiyear rate plan.

Moreover, the erosion of the cost containment incentive risks reducing any cost-saving benefits that may otherwise accrue to customers through the annual downside-only reconciliation process, in a scenario in which the Company underspends on plant additions in a rate year relative to the forecast.

Q. How does the Company's proposed F-Factor create additional administrative burden that multiyear rate plans are intended to reduce?

A. The Company's proposal to apply the partially externally-indexed revenue cap only to O&M expense but not to capital projects would create complexity and need for regulatory oversight regarding allocation of Company expenses (e.g., Company labor and direct and indirect overheads) to supplemental recovery for capital projects.

The F-Factor approach proposed by the Company requires an annual prudence review to reconcile actual capital plant projects placed into service during the rate year, relative to the authorized F-Factor forecast.

Typically, MRPs do not require annual prudence reviews because the linkage between revenues and actual costs during the stayout period is temporarily broken. Prudence review of capital investments that are recovered through the MRP, therefore, typically does not occur until a subsequent rate case. An annual prudence review in the manner proposed by the Company would reduce the efficiencies that a multiyear rate plan is intended to produce.

Q. Please elaborate on the challenges related to capitalization of overheads that will make implementation and oversight of the F-Factor and annual prudence reviews more administratively burdensome?

A. Under the Company's proposal, the typical allocation of Company labor and/or Company general overheads in the capitalized costs of capital projects would become a critical accounting consideration. Because the amount of Company labor and Company overhead expenses booked to capitalized projects affects the amount of revenue allowed as part of the F-Factor during the MRP term, it is important to carefully examine and review the accounting details regarding how these Company expenses are booked to capitalized projects.[20] This would require identification and standardization of related accounting

[20] OCC-860.

protocols and would require probative examination, complicating the implementation of the annual PBR reconciliation reviews.

The Hawaii Commission's experience provides an illustrative example of the implications that warrant consideration. For example, during the review of capital projects for which supplemental revenue (above the PBR revenue formula) is allowed, the Hawaii Commission examined the practices for assigning general company overheads for supplemental recovery and issued protocols limiting what types of overheads could be included in recovered amounts.[21] For instance, Company labor dedicated to a project would be allowed, as well as direct overheads associated with the Company labor, but general overheads would not be allowed. The Commission determined that only expenses that were incurred due to the existence of the project were allowed; overheads that were for costs that would be incurred regardless of the existence of the project were not allowed. This matter was not anticipated in the Hawaii Commission's PBR Framework Order but arose during the annual review process that required substantial examination.

Q. What other differences do you observe between the treatment of capital as envisioned in the RE01 PFD and what the Company has proposed, and what concerns do they present?

A. In the RE01 PFD, the Authority established that the cut-off for plant-in-service and accumulated depreciation for inclusion in base rates was the close of the evidentiary

[21] Hawaii Public Utilities Commission, *In the Matter of the Application of In the Matter of the Application of Maui Electric Company, LTD. For Approval to Commit Funds in excess of $2,500,000 (excluding customer contributions) for the Switchyard/Synchronous Condenser Project and to Recover Costs through the Exceptional Project Recovery Mechanism*, Docket No. 2020-0167, Order No. 38279 (March 17, 2022).

record.[22] In contrast, the Company proposes to include forecasted capital additions through the end of the Rate Year in going-in rates. The Company's proposal to include forecasted capital additions through the end of the Rate Year in going-in rates heightens the risk of double recovery. As the Authority noted in the RE01 PFD, "Only plant that is both prudent and used and useful as of the close of the evidentiary record is eligible for inclusion in the EDC's rate base," while the incremental capital funding mechanism (i.e., CT-Bar) could compensate the EDC for incremental plant entering service during the Rate Years of the MRP.[23]

Q. Does the Company's proposal, including forecasted capital additions based on a Targeted System Performance plan etc., adequately address the goals that informed the development of an IDSP process in RE03?

A. No. We recommend the completion of a thorough and comprehensive IDSP process before evaluating the PBMRP framework and the projected capital additions and forecasted capex as proposed by the Company. The capital forecast is essential for understanding which investments are actually necessary, which parties cannot adequately assess without a full IDSP. To the extent there are investments that are appropriate to fund while an IDSP is in development, we recommend that the Authority consider using a project-based capital funding mechanism on a case-by-case basis.

[22] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 at p.15

[23] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (Appendix A, page iii); *see also*, Docket No. 24-10-04, Decision dated March 3, 2026, p. 25-26 ("Specifically, a utility is permitted to include new plant additions, provided the company can demonstrate that (1) the plant is used and useful and (2) the costs were prudently incurred. Further, a utility is permitted to submit evidence to meet this evidentiary burden through the close of the record; however, projects first identified after the filing of the rate application may constitute an amendment to the application subject to Conn. Agencies Regs. § 16-1-58").

Q. How would you characterize the company's TSP compared to the proposed IDSP document from the RE03 Proposed Final Decision issued in July 2026?

A. The IDSP planning process described in the RE03 PFD proposes a comprehensive planning approach that accounts for emerging technology, policy goals, changing customer behavior and load forecasts, and evolving system grid needs.[24] The Company's submitted TSP provides a narrower view of the grid and its solutions, does not account for uncertainty, limits the information provided to stakeholders compared to an IDSP, and omits the longer-term strategy often present in an IDSP.[25] Table D below summarizes how the content submitted as a part of the TSP differs from the proposed content to be included in the IDSP.

Table D. Differences Between the TSP[26] and an IDSP[27]

RE03 PFD IDSP Document Section	*Proposed IDSP Content*	*Content Provided in Company TSP*
Executive Summary	Identifies key points from each section of the document	Not applicable/included
Planning Policy	Discussion of relevant state and local goals and policies that inform grid planning, providing useful context for understanding subsequent IDSP sections.	No state policies referenced in plan[28]

[24] Docket No. 21-05-15RE03, Proposed Final Decision, July 17, 2026 (page 7).

[25] The Company notes in its response to OCC Interrogatory OCC-566 that the "TSP Plan aligns generally with the IDSP content, particularly in terms of the state of the system and investment plans to address current and projected needs, while also reflecting practical differences." OCC characterizes the Company's TSP based the assessment summarized in Table D. OCC-566 The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-566, Sept. 22, 2026, p. 2.

[26] Based on OCC-566 The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-566, Sept. 22, 2026, pp. 2-3.

[27] Docket No. 21-05-15RE03, Proposed Final Decision, July 17, 2026 at p.7 (Appendix A, page i)

[28] In Exhibit CLP-TSP-2 (page 20-21), the Company references the evaluation of long-term policy objectives in its long-term demand assessment. However, no specific policy objectives are shared as a part of the TSP filings.

RE03 PFD IDSP Document Section	*Proposed IDSP Content*	*Content Provided in Company TSP*
Current State of the System	Provides an overview of existing grid conditions including, but not limited to, capacity, reliability, and DER integration issues, and describes the current operating condition of the grid as context for the planning documented in the IDSP.	Included[29]
IDSP Methodology	Explains the planning methods used to conduct grid planning and produce the IDSP, and provides a fundamental context and an essential reference for subsequent sections elaborating on the identification of grid needs and solution selection.	Eversource includes an overview of its methodology for developing its proposed TSP. However, the TSP methodology is different from what would be included in the IDSP, as noted in the differences in the stakeholder engagement and social equity, forecasting, grid needs assessment, and solutions selection below.[30]
Stakeholder Engagement and Social Equity	Reports on stakeholder engagement that occurred during IDSP development, including identification of which stakeholder inputs were incorporated into planning assumptions or investment decisions, including how and where they appear in the IDSP; and a brief rationale for any material stakeholder proposals that were not adopted.	No stakeholder engagement informed the development of the TSP. Equity listed as a consideration for the Resiliency Plan[31] and as a consideration for capital investment selection.[32] However, the TSP does not cover how equity factored into investments that were not related to resiliency.

[29] OCC-566 The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-566, Sept. 22, 2026, p. 2.

[30] OCC-566 The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-566, Sept. 22, 2026, p. 2.

[31] Resiliency Plan prioritizes high storm CEMI locations first. Exhibit TSP-3, page 119

[32] Exhibit TSP-3, page 33

RE03 PFD IDSP Document Section	*Proposed IDSP Content*	*Content Provided in Company TSP*
Load Forecasting	Summarizes the utility forecasts for the distribution system. Proposed to include: • Scenarios - three forecasts (low, middle/baseline, high) representing alternative technology adoption scenarios, each consisting of five prior years (including actual data and historical forecasts) and 10 forecast years. Forecasts will be reported at the system, planning region, substation, and feeder levels.[33] • Peak load charts: A line chart of peak load in MW for actual peak, 90/10 peak, and 50/50 peaks, for all three scenarios (low, middle/baseline, high). • Historical EV and DER Adoption: Historical adoption of EVs, heat pumps, solar, and battery storage by feeder.	Load forecast shared at the system level, inclusive of 10 prior years and 10 forecast years. However, there are no scenarios or other methodologies that account for forecast uncertainty. There are also no forecasts shared at the planning region, substation, or feeder level. Peak load charts are included for NWS (non-wires solutions) locations, but are not included for any other locations. Historical EV and DER adoption by feeder is also not included.
Grid Needs Assessment	Assessment of grid needs, including: • Policy drivers • Alignment with Non-Wires Solutions (NWS) process • Steady-state analysis • N-1 Contingency Analysis • Reliability and Resiliency Analysis • Hosting Capacity Analysis • DER Interconnection Plan	Includes reliability and resiliency analysis, hosting capacity analysis, and alignment with NWS process. Does not include policy drivers, a comprehensive steady-state analysis, a comprehensive N-1 contingency analysis,[34] or a comprehensive DER interconnection plan.

[33] Additionally, the RE03 PFD notes that DR, TOU, and social equity-focused incentive programs with quantifiable data that are already developed and in place or have already been designed but are not yet in place should be incorporated into the load forecasts.

[34] Note that Eversource's methodology indicates that they conducted a steady state analysis and an N-1 contingency analysis, but the results of the analysis were not shared as a part of the TSP.

RE03 PFD IDSP Document Section	*Proposed IDSP Content*	*Content Provided in Company TSP*
Solutions Selection Process	Assessment of solutions to grid needs, including: • Coordination with NWS Process • Scenario-based least regrets analysis • DER interconnection plan • Standard project documentation (varied by cost tier) • Cross-reference to capital investment plans	Includes coordination with NWS process. Does not include scenario-based least regrets analysis of large investments, a comprehensive DER interconnection plan, or the standardized project documentation.
Capital Investment Plan	Summary of capital investments, including: • Summary table • Explanatory narrative • Individual project listing table appendix • Supplemental filing with a financial analysis or standardized documentation	Includes a summary table, explanatory narrative, and individual project listings. Does not include standardized project documentation that is coordinated with the solutions selection process.
Long-Term Strategic Plan	Summary of the long-term strategic plan, including: • Demand assessment (10-25 years) including a broad range of scenarios • Explanatory narrative discussing assessment and potential solutions • Summary of outcomes from long-term strategic plan working group • Strategic narrative discussing company plan to achieve state's clean energy objectives	Not included in the TSP

Q. How do the differences you highlighted above limit the TSP's efficacy in forecasting costs?

A. The proposed planning process in RE03 allows for iteration of utility forecasted costs through stakeholder engagement and also provides stakeholders substantially more time to review utility forecasts. It additionally proposes the creation of working groups to allow

for data sharing, scenario input, and discussion of long-term strategy in utility planning. Without a thorough stakeholder engagement process, it is difficult to determine whether the utility is using best practices or is appropriately accounting for stakeholder needs in its cost forecast.

The utility forecasts do not account for uncertainty nor do they provide granularity; without this, it is difficult to evaluate the forecast's sensitivity to certain inputs, assess the prudency of the investments that have been included in the forecast, or determine whether there is any flexibility on the timing of the investment if some spending needs to be prioritized.

Additionally, the IDSP includes both a 10-year forecast and a long-term (10-25 year) forecast to demonstrate how the utility plans to modernize the grid and achieve state policy goals in the long run. The TSP does not provide a long-term forecast, making it difficult to determine whether the proposed expenditures will help benefit or reduce costs for customers in the long run.

Unlike the IDSP, the TSP does not include an assessment of why the forecasted investments are least-regrets solutions. Without this analysis, it is difficult to determine what other investments were considered by the utility.

Q. How do these concerns with the Company's TSP heighten the concerns of cost-containment identified above?

A. The F-Factor, particularly without the analytical grounding of an IDSP, increases the risk that the Company's capital addition forecast is inflated. As noted above, a higher capital forecast will make it easier for the Company to gold plate its capital projects during

construction, both to minimize reconciliation and increase the Company's earnings through higher capital returns.

The Company's proposal of a fully forecasted capital plan based on a partial analysis as represented in the TSP creates an incentive for the Company to spend up to its allowable amount, retaining the problem of capex bias that was a motivation behind the initiation of the RE01-03 proceedings and the consideration of a performance-based regulation framework.

Q. What additional concerns do you have with respect to removing capital plant addition recovery from the externally indexed attrition relief mechanism and basing it on a multi-year forecast?

A. Most enterprises (utility or otherwise) are only marginally successful at achieving projected timelines for construction projects.[35] The Company is no exception. A PURA-commissioned management audit found that the Company's actual capital spending differed from plan by more than 10 percent in three of the five years from 2017 to 2021, including a 25.8 percent variance in 2018.[36] It would be challenging for any entity to make a four-year capital budget that will be implemented as planned with respect to timing and cost. To emphasize this point further, we note that the Company's forecasted capital

[35] Research finds that only 8.5 percent of more than 16,000 projects worldwide met their original cost and schedule estimates. (Bent Flyvbjerg and Dan Gardner, *How Big Things Get Done*, Penguin Random House, 2023, page 8). Another analysis finds that 75 percent of surveyed US and Canadian project owners reported late projects, which averaged 69 days behind original estimates. International Data Corporation, "Owners at the Leading Edge", 2021, page 6.
https://assets.ctfassets.net/8pep15rt0kef/6mowOFymkHpBeyXMXhX3m1/4deff7dc768666168864496602a8f212/2021OwnersSurvey.

[36] Exhibit CLP-ELP-4, FTI Consulting, Management Audit of Eversource Energy's Connecticut Companies (Feb. 11, 2025), page 205, Figure 2-24.

expenditure in this proceeding represents a 49% increase over average historical capital expenditure from 2017-2025 – which, presumably, will require a requisite increase in utility capacity to manage and oversee.[37]

Moreover, given the rapid change in capabilities that are unlocked via technological advancement and learnings from implementation, the plans made by a utility today cannot reflect the potential changes to least-cost solutions, nor the changes in priorities for some major components of the capital plan. Removing capital plant additions from the revenue cap formula effectively solidifies a plan as appropriate, without a complementary incentive to alter the plan as circumstances – costs and otherwise – evolve over time.

Finally, the differentiation between those capital costs that are included in going-in rates as depreciation expenses, and those that are recovered via the F-Factor, is unclear. The bulk of the itemized capital needs in the Company's proposal are for assets and (largely) asset replacement programs, such as building inventories of materials for preparedness.[38] We are concerned that the Company proposal does not recognize that some capital additions would already be covered by what is provided in base rates. Such programs should be included in existing going-in rates by way of being in accumulated rate base (and resulting depreciation expense) for prior-year ongoing implementation. Our rationale for such treatment is that these do not seem to be, for the most part, new programs, but are the types of infrastructure replacement to be expected as constant addressing backlogs of deferred

[37] OCC-424
[38] Exhibit CLP-ELP-1, page 66–70

maintenance. However, from the Company's application, it is not clear that the revenues already included in going-in rates for such programs would be properly recognized.

For the sake of consideration, even the CT-Bar – which OCC did not and does not support because of its failure to create adequate cost containment incentives – would more appropriately recognize the recovery of such infrastructure replacement programs.[39] The CT-Bar was designed to deduct depreciation expense already included in going-in rates from plant additions eligible for supplemental recovery.

Q. The X-Factor in the partially externally-indexed revenue cap is based on a TFP study conducted by Eversource's consultant, London Economics International . To what extent did the Company and its consultant follow the guidance established in RE01 regarding the process for conducting a TFP study?

A. The Authority has established detailed guidance in RE01 intended to make a TFP study transparent, reproducible, and subject to meaningful review by the Authority and intervenors.[40] However, the Company and its consultant, London Economics International ("LEI"), did not follow key parts of this guidance. Instead of providing an open, reproducible, and iterative productivity analysis, the Company and LEI relied in part on confidential data and on code that parties could not run as provided;[41] declined to run several alternative scenarios that OCC requested in discovery;[42] based the proposed X-

[39] Docket No. 21-05-15RE01, OCC Letter in Lieu of Written Exceptions (August 15, 2025), page 2; see also Docket No. 21-05-15RE01, OCC Written Comments in Response to the Revised Straw Proposal (March 26, 2025), page 12–14.

[40] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (page 24).

[41] Docket No. 26-05-10, Ruling on Motion No. 10, August 3, 2026, p. 3; Docket No. 26-05-10, Exhibit CLP-PBR-3B, July 14, 2026, p. 5.

[42] Docket No. 26-05-10, Company Response to OCC-538, September 15, 2026.

Factor on a single output measure, customer count;[43] and offered parties no working sessions to review the study with LEI. In detail, the Company's filing falls short of these directives across several[44] critical dimensions.

First, the Company and LEI met RE01's data-sharing guidance only in part. The Authority guidance in RE01 PFD requires that all TFP study data be provided and run on an open-source platform, with the code made available.[45] They serve a practical purpose. The X-Factor affects how much OM&A revenues can grow in each year of the PBMRP, yet the Company and its consultants control the underlying data, model, and analytical choices. Transparent data and models that parties can run help level the playing field and allow the Authority and parties to test other reasonable assumptions. This lets the Authority see how much the result depends on those choices, instead of relying on a single estimate prepared by the Company. However, LEI and the Company employed a proprietary TFP and benchmarking model, some of the data for which was obtained from a confidential third-party database.[46] The underlying data was granted protected treatment by the Authority.[47] As a result, testing model assumptions in the collaborative approach envisioned in RE01 was not possible.

[43] Docket No. 26-05-10, Company Response to AMTRAK-010, September 22, 2026.

[44] To our knowledge, neither the Company nor LEI offered parties a technical session or working meeting on the study in this proceeding. Parties could review the study only through the filed exhibits, the protected workpapers, and written discovery.

[45] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025, (page 22)

[46] Docket No. 26-05-10, Motion No 10. for Protective Order and LEI Affidavit, Attachment C, July 15, 2026 (page 2)

[47] Docket No. 26-05-10, Motion No 10. Ruling for Docket 26-05-10, August 3, 2026 (page 3)

Second, the plain-language documentation and open-model requirements were also not met. LEI's pre-filings do describe the index method and several major assumptions.[48] That description is useful, but it is not a substitute for a data dictionary, complete metadata, source-to-model transformation records, executable formulas, and code. The code that LEI did provide does not meet the open-model requirement either. LEI provided code for its econometric benchmarking models written in a commercial software rather than an open-source platform. Parties without this commercial software license cannot run the code. In addition, the code relies on the commercial software's data file that was not provided in its native format, so even parties with the commercial software cannot run the code as provided and reproduce LEI's results.[49]Third, the alternative-scenario requirement was not meaningfully met. The Authority specifically mandated that parties have the opportunity to request alternative sensitivities. However, when OCC submitted a discovery request that LEI provide the results of a sensitivity analysis isolating the highly anomalous 2019–2020 period, LEI declined.[50] LEI argued that removing individual years would introduce "selection bias."[51] We are not recommending permanently excluding these observations from the regulatory record, but are instead recognizing that testing the model's sensitivity to an unusually volatile macroeconomic period provides important information regarding the stability of the proposed productivity factor. LEI's decision not to conduct the standard

[48] Docket No. 26-05-10, Exhibit CLP-PBR-1, July 14, 2026
[49] Docket No. 26-05-10, Exhibit CLP-PBR-3B (page 5), July 14, 2026
[50] Docket No. 26-05-10, OCC Interrogatories Set 9, August 20, 2026
[51] Docket No. 26-05-10, OCC-445, September 03, 2026

econometric stress testing has prevented parties from better understanding the stability of the results.

Fourth, LEI uses incomplete output metrics. In the RE01 PFD, the Authority required TFP study outputs to be measured in customer count, delivered energy, and peak demand.[52] However, LEI's study evaluated output solely on customer count, omitting delivered energy and peak demand; we were unable to find the evaluation of these other measures within the filed working papers.[53] LEI acknowledged that sales was the only alternative output measure it evaluated, and that it "did not separately evaluate peak demand" because it is "impossible to get high quality data."[54] This omission inherently skews the productivity evaluation by ignoring the efficiency gains required to serve higher peak loads or throughput without necessarily adding new customers.

Finally, the RE01 PFD states that any TFP study "should employ reasonably accessible techniques and methodologies."[55] In our view, a study meets the standard when the Authority and parties can follow how the inputs lead to the result and can test how much the result depends on key choices. (A breakdown of the PFD's expectations compared to the Company's submission appears in Table B). LEI selected the index method in part because it considered the approach relatively straightforward and easy to explain to a

[52] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (page 22).
[53] Docket No. 26-05-10, Exhibit CLP-PBR-2A, Exhibit CLP-PBR-3A, and Exhibit CLP-PBR-3B, July 14, 2026
[54] Docket No. 26-05-10, AMTRAK-010_Final, September 22, 2026
[55] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (page vii).

diverse audience.[56] However, the relative simplicity of the methodology does not, by itself, make LEI's application of that methodology reasonably accessible for independent review as contemplated by RE01. The test is whether the Authority and intervenors can recreate the result, alter assumptions, inspect intermediate calculations, and evaluate the consequences. The record available to parties did not permit that level of review.

Table E below summarizes these issues, contrasting the Authority's original guidance in RE01 with LEI's actual execution:

Table E. Comparison of Eversource's TFP Study Process to PURA Guidance from RE01

Guidance included in RE01 PFD[57]	*Did the Company or its consultants comply with this guidance?*
All TFP Study data should be provided to PURA and other parties and intervenors (under a non-disclosure agreement, if appropriate).	Partially. The Company provided Excel workpapers under protected treatment, but we note some inconsistencies between the Excel workpapers, which do not fully match the PDF workpapers, and some data in the PDF workpapers is incomplete.
All TFP data, meta-data, and assumptions should be described in plain language.	No. LEI did not provide a complete plain-language description. Without this, parties could not understand how data was structured, assess modeling assumptions, or determine how those choices affected LEI's results.
All models should be run on an open-source platform with the code provided to PURA and other parties and intervenors (i.e., if using Excel or R, all formulas or code must be distributed to all stakeholders).	No. LEI provided code for its econometric benchmarking models, but that code was written in a commercial software rather than an open-source platform. The code also relies on a data file that was not provided in its native format, so it cannot be run as provided.

[56] Docket No. 26-05-10, Exhibit CLP-PBR-1, July 14, 2026 (page 25).
[57] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025

Guidance included in RE01 PFD[57]	*Did the Company or its consultants comply with this guidance?*
Parties and intervenors have the opportunity to run alternative scenarios or request that the Authority and/or the EDCs run alternative scenarios.	No. LEI expressly declined OCC's request to calculate a sensitivity test for the anomalous 2019–2020 period, preventing stakeholders from verifying the stability of the proposed productivity factor.
Parties and intervenors have sufficient time to conduct an iterative and substantive process.	No. The Company offered parties no opportunity for briefing or working sessions with its consultant to discuss the TFP study in an iterative, substantive manner.
TFP study outputs should be in terms of customer count, delivered energy, and peak demand	No. LEI's PFP study was provided exclusively in terms of customer count, omitting delivered energy and peak demand metrics.
Any TFP study should employ reasonably accessible techniques and methodologies.	In part. LEI described its method, but parties would not be able to recreate the result, change assumptions, or check intermediate calculations using the provided information.

Q. What concerns do you have about the Company's departure from PURA's guidance for conducting a total factor productivity study?

A. Our concern is that LEI has not established that its OM&A PFP estimate is sufficiently reliable to set a –0.03% X-Factor. The X-Factor would affect OM&A revenue increases every year of the PBMRP. The fact that no other party has presented a competing productivity estimate does not, by itself, demonstrate that LEI's estimate is reliable, particularly where LEI declined to run the alternative scenarios that parties requested. The Company, not other parties, bears the burden of proving that its proposed rates are just and reasonable, and that includes the proposed X-Factor.[58]

[58] General Statutes § 16-22.

The Company did provide LEI's native workpapers under protective treatment.[59] But access to workpapers is not the same as the ability to test whether the result holds up under other reasonable assumptions. As discussed above, LEI declined to run the sensitivity analyses OCC requested in discovery. It did so even though it agreed that the 2019–2020 change in OM&A productivity, viewed on its own, is not representative of productivity expected during the PBMRP term, and it confirmed that it did not perform any formal structural-break or outlier test.[60] This gap matters because LEI explains that its index methodology does not produce conventional confidence intervals or forecast-error measures. Replication and sensitivity testing are therefore among the main ways to check whether the result is stable.[61]

LEI's own results self-prove our concern, showing that major methodological choices materially affect the estimate. The sensitivity analysis indicates that the productivity result changes depending on the output measure used: when using sales instead of number of customers as the output, the average annual OM&A PFP for EDCs in the U.S. is -0.99%, significantly different from the -0.03% based on number of customers.[62] We are not asserting that the productivity per customer is necessarily a worse output. Rather, the difference demonstrates why the Authority should evaluate all output measures identified

[59] Docket No. 26-05-10, Company Response to OCC-534, September 15, 2026 (page 22)

[60] Docket No. 26-05-10, Company Response to OCC-446, September 3, 2026 (page 1)

[61] "*It is important to note that the index method, because it is a numerical technique as opposed to a statistical technique, does not lend itself to statistical analyses (confidence levels or forecast error measures). Therefore, interpreting differences in estimated TFP growth rates arising from these index values necessarily involves studying differences in inputs and data, and if necessary evaluating consequences of specific methodological choices*". Docket No. 26-05-10, Exhibit CLP-PBR-1, July 14, 2026 (page 26)

[62] Docket No. 26-05-10, Exhibit CLP-PBR-2, July 14, 2026 (page 70)

in RE01, including productivity per peak demand and delivered energy, before selecting a single point estimate.

In summary, LEI has not adequately connected the historical estimate to the 2027–2031 PBMRP term. Historical industry productivity may inform an X-Factor, but the record should explain why the selected period, output measure, and methodology provide a reasonable expectation for a forward-looking period involving significant changes in load, electrification, grid investment, labor costs, and utility operations. Because the Company controlled the data, assumptions, sensitivities, and final estimate without the full review process contemplated in RE01, the Authority cannot determine from the current record whether –0.03% is stable, representative, or the best forward-looking OM&A productivity expectation. These deficiencies, therefore, go directly to the evidentiary weight PURA should assign to the result. With only the Company submitting a proposal and the Company's consultant refusing to conduct the requested sensitivities or provide productivity analysis outputs on other terms, it is difficult to have confidence that –0.03% is appropriate.

Q. Given your concerns, what recommendations do you offer to PURA regarding the productivity factor in this proceeding?

A. If the Authority decides to approve any version of the Company's PBMRP application, we recommend that the Authority set the X-Factor at zero for the proposed PBMRP term rather than adopting the Company's proposed –0.03% X-Factor. As discussed above, the current

productivity study does not provide a sufficiently tested basis for reducing or increasing the OM&A revenue path through a non-zero productivity adjustment.

PURA has discretion under the RE01 framework to determine the appropriate X-Factor based on the evidence in the rate proceeding, including setting the X-Factor at zero.[63] Setting the X-Factor at zero would avoid embedding an inadequately supported productivity estimate into rates. It would not prevent the Company from retaining efficiencies achieved by managing OM&A below the revenue path established by the remaining components of the formula. Nor would it prevent PURA from adopting a non-zero X-Factor in a future proceeding supported by a more complete and reviewable record. Given the limitations identified above, we recommend that PURA set the X-Factor at zero.

We are also concerned that the Company proposes to apply productivity adjustment only to OM&A while providing capital recovery through the separate capital recovery mechanism.[64] The Company has not adequately demonstrated how those two mechanisms will operate together. PURA should not adopt the proposed X-Factor without first understanding its effect within the Company's broader PBMRP.

Q. Please describe your concerns with a 0.5% Z-Factor threshold for exogenous events.

A. The Company's proposed Z-Factor includes a significance threshold of 0.5% of total distribution revenue. The Docket No. 21-05-15RE01 PFD had included a 0.75% threshold.

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[63] "*The Authority has the discretion to set the X-Factor value based on the evidence in a given rate amendment proceeding, including setting the X-Factor at zero*.", Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025, (page vi).

[64] Docket No. 26-05-10, Exhibit CLP-PBR-1, July 14, 2026 (page 40)

In general, we support Z-Factor thresholds that are high enough to ensure that the mechanism is only used for events that have a material financial impact on the EDC, but not too high as to prevent its use in justified cases. We are concerned that a threshold of 0.5% of the Company's total distribution revenue is too low and could make more ordinary cost fluctuations eligible for exceptional pass-through treatment, potentially weakening the cost containment incentives that the PBMRP is intended to create. A higher significance threshold could help maintain the cost containment incentives of the PBMRP, while allowing for appropriate treatment of costs associated with exogenous events during the MRP outside of Company control.

Q. Please describe your concerns with the Company's proposed S-Factor.

A. The S-Factor is an important component of a revenue cap formula because it allows customers to receive a share of the expected productivity gains that occur during the MRP. While reconciliation protects against forecast errors, the S-Factor provides an ongoing efficiency incentive even when spending remains within the forecast. We are concerned that the Company's proposed S-Factor (Customer Dividend), as part of a partially externally-indexed revenue cap formula, would only be applied to O&M and thus unable to incentivize cost containment and share efficiencies in capital investments. As the RE01 PFD explains, "The S-Factor, also known as a Stretch Factor or 'customer dividend', is included in the Revenue Cap Formula to encourage an EDC to make greater efficiency gains, particularly when compared to a peer group as measured via a benchmarking

study".[65] The reconciliation mechanism envisioned for capital in the Company's proposal is not comparable to the consistent downward adjustment to allowed revenues that the S-Factor would provide if capital was included in the externally-indexed revenue cap formula, as was envisioned in the RE01 PFD. The Company's proposed capital reconciliation process may protect customers from paying the forecasted revenue requirement for capital additions that are delayed, canceled, or otherwise not placed in service. But it does not require the Company to achieve efficiencies relative to an external benchmark or to reduce allowed revenues in response to opportunities to deliver the same level of service with fewer capital expenditures. An S-Factor applied to capital as part of a revenue cap formula would create incentives for the Company to seek out cost efficiencies, contain capital costs, and allow customers to share in those efficiency gains.

Q. Please describe your concerns with the Company's proposed I-Factor.

A. The Docket No. 21-05-15RE01 PFD includes an I-Factor that would be applied to both capex and opex as part of the externally-indexed revenue cap's I-X mechanism. The PFD proposed that the I-Factor would be "based upon the most recent four quarters of the Gross Domestic Product Price Index (GDPPI) commencing from the end of the four quarters used for either Going-in Rates (in the case of the first annual I-Factor adjustment) or the most recent I-Factor reset (in the case of Rate Years 2 through 4)."[66] In contrast, the Company's proposed I-Factor would only be applied to O&M as part of the partially externally-indexed

[65] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (Appendix A, page vii).
[66] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (Appendix A, page vi).

revenue cap. The Company's proposed I-Factor would be based on a composite O&M input price index consisting of the Employment Cost Index ("ECI") and GDP-PI, weighted using the industry's labor and non-labor OM&A cost shares, and includes a floor of 0 percent and a cap of 5 percent. Unlike the Company's proposal, the Docket No. 21-05-15RE01 PFD does not specify that the I-Factor "must be non-negative."[67] We are concerned the Company's proposal would not allow for the PBMRP formula to reflect periods in which the applicable inflation index is negative.

Q. Please describe your concerns with the lack of off-ramps included in the Company's proposal.

A. The exclusion of off-ramps in the Company's proposal eliminates a key mechanism to help avoid unintended consequences. In general, off-ramps with specific, well-defined conditions provide important safeguards when included as part of a multi-year rate plan because they allow for reevaluation if course corrections are needed. As the Authority stated in the Docket No. 21-05-15RE01 PFD, "unforeseen situations could arise during the MRP that may warrant the initiation of a new rate amendment proceeding."[68]

It is important to note that when poorly designed, off-ramps can undermine the incentives created by a multi-year rate plan with a revenue cap. In general, if the threshold conditions are too easily met, a utility may exit the MRP prematurely, weakening the incentive to contain costs within the revenue cap.

[67] Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Exhibit CLP-ELP-1, July 14, 2026, Page 86 of 164.

[68] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025 (Appendix A, page ii).

The inclusion of off-ramps in a multi-year rate plan can provide stakeholders with the opportunity to petition regulators to initiate an off-ramp process when they consider a threshold has been met. The exclusion of off-ramps from the Company's proposal removes the opportunity for stakeholders to petition the Authority in this way and excludes potential guardrails that can help to ensure the multi-year rate plan is working as intended.

In its response to OCC-433, the Company also states that the Consumer Dividend, the cap on the I-Factor, and the Earnings Sharing Mechanism provide sufficient "guardrails" that are intended to "provide relief".[69] In contrast, the Proposed Final Decision in Docket No. 21-05-15RE01 included off-ramps related to four scenarios: EDC financial condition, windfall profits, falling interest rates, and excess storm costs. These proposed off-ramps were the product of several years' worth of stakeholder input and review. We believe that the types of off-ramps included in the Docket No. 21-05-15RE01 PFD could provide additional customer relief, beyond the mechanisms that the Company has identified, and would provide additional opportunity for stakeholders to petition the Authority to initiate an off-ramp proceeding. We recommend that before approving any PBMRP, the Authority revisit the off-ramps identified in Docket No. 21-05-15RE01 and include well-defined off-ramps in the Company's PBMRP proposal. We recommend, in particular, inclusion of off-ramps related to EDC financial condition, windfall profits, falling interest rates, and excess storm costs.

[69] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Set OCC-09, Date Issued August 20, 2026, OCC-433, page 1.

Q. Does the management audit adequately identify potential opportunities for Eversource to achieve cost efficiencies?

A. No. Based on our review of the management audit conducted by FTI Consulting (Exhibit CLP-ELP-4), we find that the analysis conducted stopped short of examining whether the Company is being frugal and cost disciplined. The scope of the audit focused on naming business processes and functions, and identifying gaps where relevant, but does not include any analysis that would lead to a conclusion about the Company's use of resources, opportunities to reduce redundancies, increase efficiency, or generate savings through changes to the Company's business processes or practices.

As explained by the Authority, the purpose of an audit as part of any application for an MRP is to "help identify cost savings opportunities prior to the new MRP."[70] To support identification of opportunities to achieve cost efficiencies, an analysis would likely include benchmarking or a comparison to other utilities and how they operate. This does not appear to have been within scope.

Q. Given the management audit was not supportive of identifying cost efficiencies, what recommendations do you have for PURA?

A. We recommend that, before considering a future PBMRP, PURA require a management audit specifically designed to identify opportunities for cost efficiencies and savings. At a minimum, the audit should benchmark Eversource's spending and practices against comparable utilities across major categories of operations and expenses, evaluate whether

[70] Docket No. 21-05-15RE01, Proposed Final Decision, July 14, 2025, page 16/

resources are being used efficiently, and identify areas where changes to business processes or practices could reduce costs. The audit should also assess whether the Company has effective internal processes to monitor spending and proactively identify cost-saving opportunities. The resulting audit should provide PURA with clear findings and actionable recommendations that can inform expectations for cost control in any future PBMRP. As discussed further in Section IV, we also recommend that PURA consider incorporating management-efficiency measures into the Performance Evaluation System so that identified efficiency opportunities, implementation, and resulting customer savings can be tracked over time and potentially inform future performance mechanisms.

Q. If the Authority is inclined to adopt a multiyear rate plan, how should it proceed?

A. As stated above, our primary recommendation is for the Authority to deny the Company's PBMRP proposal and to approve a one-year rate plan in this docket. Once PBR guidance has been established outside of this docket, the Company could file a new rate application.

However, if the Authority determined that it wants to adopt a comprehensive PBR multiyear rate plan in this proceeding, it might consider approving rate year revenues based on the 2025 test year. Then, upon establishing first-year revenue requirements and rates, the PUC could instigate a reopener to combine both O&M and capital under an externally indexed revenue cap formula, requiring a new I-Factor, S-Factor, and X-Factor to be determined. In addition, we would recommend PURA also require an IDSP process to inform capital spending needs for the subsequent three rate years, and to inform a determination of whether it will consider an incremental capital funding mechanism that is

used to recover costs on a case-by-case basis to allow supplemental revenues for capital investments beyond the escalation allowed by the revenue cap formula.

IV. PERFORMANCE EVALUATION SYSTEM

Q. What is the purpose of this section?

A. This section evaluates the Performance Evaluation System proposed by the Company, including its proposed performance incentive mechanisms, reporting metrics, and treatment of the Metrics and Scorecards identified in Docket No. 21-05-15RE02 ("RE02"). We compare the Company's proposal to the framework set forth in the July 2026 RE02 Proposed Final Decision ("RE02 PFD"), assess whether the proposed PIMs satisfy the Design Principles established in RE02, and identify modifications that we recommend the Authority make in adopting a Performance Evaluation System in this proceeding.

Q. Do you recommend that the Authority adopt a Performance Evaluation System in this proceeding if it does not approve the Company's proposed PBMRP?

A. Yes. We recommend that the Authority adopt a Performance Evaluation System in this proceeding regardless of whether it approves the remainder of the Company's proposed PBMRP. Metrics, Scorecards, and PIMs can provide meaningful transparency into utility performance and strengthen incentives and accountability for priority customer outcomes independent of the revenue adjustment mechanisms associated with a multiyear rate plan. We therefore do not recommend delaying adoption of the Performance Evaluation System while other components of the PBR framework continue to be developed.

Q. At a high level, what concerns do you have about the portfolio of performance incentive mechanisms that the Company has proposed?

A. We have several concerns with the Company's proposed portfolio.

First, the Company departs in important respects from several of the potential PIM designs considered in RE02. Some departures may ultimately be appropriate, but the Authority should evaluate whether the underlying objectives and design considerations identified in RE02 remain applicable and whether the Company has provided sufficient evidence to support a different approach.

Second, the Company has not adequately demonstrated that the overall size of its proposed incentives and penalties, or the allocation of that financial exposure among individual PIMs, is appropriately calibrated to the outcomes the PIMs are intended to achieve.

Third, the Company proposes financial incentives for several activities that appear more consistent with routine utility operations or that the RE02 PFD treated as Metrics or Scorecards. A measure can provide useful information or reflect an important customer outcome without necessarily warranting an additional shareholder incentive.

Q. How should the Authority consider the RE02 record in evaluating the Company's proposed Performance Evaluation System?

A. RE02 provides an important evidentiary and analytical foundation for evaluating the Company's proposal in this proceeding. Over the course of that proceeding, the Authority and stakeholders considered the purposes served by individual Metrics, Scorecards, and potential PIMs, the customer outcomes they were intended to advance, and design considerations such as appropriate benchmarks, utility control, and the role of financial incentives.

We do not suggest that every mechanism identified in the RE02 PFD must be adopted without modification. However, where the Company proposes a materially different approach, the Authority should consider whether the underlying rationale for the RE02 mechanism still applies and whether the Company has provided sufficient evidence to support the departure.

Q. What design principles should the Authority apply when evaluating the PIMs proposed in this proceeding?

A. The RE02 PFD identifies Design Principles that provide a useful framework for evaluating the mechanisms proposed in this proceeding (see Table F). Among other things, the principles recognize that Metrics, Scorecards, and PIMs serve different functions, and impose additional requirements on PIMs because they carry financial consequences. In particular, PIMs should address performance under the Company's direct or indirect control, incentivize exemplary performance or disincentivize substandard performance, advance a clearly stated performance objective, and be cost-effective and appropriately sized.

We apply those principles throughout our evaluation of the Company's proposal below.

Table F: RE02 PFD Design Principles for the Performance Evaluation System[71]

Design Principle	*Metrics*	*Scorecards*	*Potential PIMs*
1. To support the achievement of desired outcomes	X	X	X
2. To enable quantification through reasonably available data and calculation methods	X	X	X
3. To enable reporting and verification	X	X	X
4. To provide compliance certainty in the short-term and adaptability over time	X	X	X
5. To reestablish a clear benchmark or target for tracking and comparison		X	X
6. To allow for comparison across peer EDCs, as applicable		X	X
7. To include performance under the indirect or direct control of EDCs			X
8. To incentivize exemplary performance and disincentivize substandard performance			X
9. To advance clearly stated performance objectives			X
10. To establish incentive mechanisms that are: (a) cost effective; (b) right-sized; and (c) and incremental as appropriate.			X

Q. What concerns do you have with the overall size and allocation of the Company's proposed PIM incentives and penalties?

A. We do not view the fact that the Company proposes greater potential penalties than rewards as a concern. An asymmetric structure may be appropriate. Penalties provide accountability for substandard performance, while financial rewards increase costs borne by customers and therefore warrant particular scrutiny.

Our concern is with how the Company determined the size of the proposed financial exposure. The Company proposes a total penalty pool of $10 million, equal to its

[71] RE02 PFD, pages 10-11.

exogenous-cost threshold, and a total reward pool of $5 million, or half of the proposed penalty pool. The Company has not adequately demonstrated why the exogenous-cost threshold is an appropriate basis for sizing potential PIM penalties. Nor has it demonstrated why setting potential rewards at half that amount results in an appropriately sized reward pool.

This distinction is particularly important for rewards. Because customers ultimately fund PIM rewards, the Authority should ensure that any potential reward is no larger than necessary to encourage incremental performance and that the expected customer benefits justify the additional cost. The same principle applies at the individual PIM level: the amount of potential reward or penalty should reflect the performance objective, the utility behavior the mechanism is intended to influence, and the value of the resulting customer benefit.

RE02 Design Principle #10 similarly provides that incentive mechanisms should be cost-effective, right-sized, and incremental as appropriate. We recommend that the Authority require the Company to demonstrate that the aggregate PIM penalty and reward pools, as well as the financial exposure assigned to individual PIMs, are appropriately calibrated to the performance objectives and expected customer benefits. In particular, proposed rewards should be limited to amounts necessary to produce meaningful incremental performance and justified by corresponding benefits to customers.

Q. How should the Authority determine whether a performance measure is appropriate for treatment as a PIM?

A. A useful performance measure is not necessarily an appropriate PIM. Metrics and Scorecards can provide transparency into utility performance and help the Authority identify trends or areas for improvement without attaching a financial reward or penalty.

Because PIMs impose direct financial consequences, a higher standard is appropriate. RE02 Design Principle #8 provides that PIMs should incentivize exemplary performance and disincentivize substandard performance. It is therefore not enough for the Company to demonstrate that an activity provides customer value or that improved performance would be desirable. The relevant question is whether a financial incentive is needed to motivate performance beyond what should reasonably be expected through ordinary utility operations and existing regulatory obligations.

We recommend that the Authority approve financial incentives only where the Company has demonstrated that the measure targets exemplary performance or discourages substandard performance, that a financial incentive or penalty is appropriate to influence that performance, and that the financial exposure is appropriately calibrated to the customer outcome.

Q. What are your specific concerns regarding the company's proposed Blue-Sky SAIDI and Blue-Sky SAIFI PIMs?

A. The Company's proposed Blue-Sky SAIDI and Blue-Sky SAIFI PIMs are generally consistent with the structure developed in RE02. Like the potential System Reliability PIM identified in the RE02 PFD, the Company proposes downside-only mechanisms that measure annual performance against a fixed five-year historical average, with penalties

beginning when performance exceeds one standard deviation above that average. The RE02 PFD explains that this structure is intended to account for normal year-to-year variability while discouraging and maintaining accountability for material degradation in reliability.[72]

Our principal concern is the Company's proposal to exclude planned outages from the calculation of both metrics. The RE02 PFD specifies that Blue-Sky SAIDI and SAIFI should be calculated using the IEEE methodology, under which SAIDI measures the average duration of interruptions experienced by customers, and SAIFI measures the average frequency of sustained interruptions, while excluding major event days.[73] It does not provide for the exclusion of planned outages.[74] Eversource acknowledges this difference and explains that it proposes to exclude planned outages because they are noticed to customers in advance and generally occur in connection with customer connections, system upgrades, or replacements.[75]

Importantly, the RE02 PFD methodology already accounts for the Company's historical experience with planned outages. Because planned outages are included in the IEEE methodology, they are reflected in both the five-year historical benchmark and annual

[72] RE02 PFD, pages 41-42.

[73] RE02 PFD, pp. 41–42; The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Exhibit CLP-TSP-1, July 14, 2026, pages 74–75.

[74] RE02 PFD, pages 41–42.

[75] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-440, Sept. 11, 2026, pages 1–2.

performance.[76] The Company therefore would not be penalized simply for continuing to undertake planned work at historical levels, particularly given the additional one-standard-deviation deadband. Rather, including planned outages preserves accountability if the frequency or duration of those outages increases sufficiently during the PBR term to contribute to material reliability degradation. By excluding planned outages, the Company would remove those interruptions from the PIM altogether, such that an increase in planned outages during the PBR term would have no effect on its PIM performance.

We recommend that the Authority retain the RE02 PFD methodology for the Blue-Sky SAIDI and SAIFI PIMs, including the treatment of planned outages.

Q. What are your specific concerns regarding the company's proposed Customer Reliability PIM?

A. The Company's proposed Customer Reliability PIM is substantially narrower than the potential PIM developed in the RE02 PFD. The RE02 PFD uses four sub-metrics: CEMI-5, which measures customers experiencing five or more interruptions in a year; the percentage of those customers who also experienced five or more interruptions in the prior year; CELID-6, which measures customers experiencing outages lasting six or more hours in a year; and the percentage of those customers who also experienced long-duration outages in the prior year. Those four measures are combined into a composite intended to

[76] RE02 PFD, pp. 41–42; OCC-440, pages 1–2.

capture both customer-level reliability performance and the persistence of poor reliability for particular customers.[77]

Eversource instead proposes to base the PIM only on the number of repeat CEMI-5 and repeat CELID-6 customers. The Company offers a reasonable rationale for focusing on repeat customers. It explains that annual CEMI-5 and CELID-6 counts can be affected by isolated events and significant year-to-year variability, whereas customers appearing on those lists in multiple years are more likely to reflect systemic reliability problems that warrant targeted Company action. The Company also identifies a legitimate mathematical concern with the RE02 composite: because the annual CEMI-5 and CELID-6 counts are orders of magnitude larger than the repeat-customer percentages, those annual counts may disproportionately drive the composite score.[78]

We agree that those concerns merit consideration, but we do not believe they necessarily support eliminating annual CEMI-5 and CELID-6 performance from the PIM altogether. Doing so removes information about the breadth of poor customer-level reliability. The Company confirms that, under its proposal, it could earn an incentive in a year when the total number of CEMI-5 or CELID-6 customers increases, provided the number of repeat customers declines.[79]

[77] RE02 PFD, pages 46–47.

[78] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-525, Sept. 15, 2026, pages 1–2.

[79] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-526, Sept. 15, 2026, pages 1–2.

We recommend retaining measures of both overall CEMI-5 and CELID-6 performance and repeat-customer performance, while addressing the scale problem identified by the Company through appropriate normalization or weighting. This would preserve the RE02 objective of measuring both the overall scale and persistence of poor customer reliability without allowing differently scaled sub-metrics to distort the result.

Q. What high-level concerns do you have with the Company's proposed Customer PIM Suite?

A. We have concerns with both the composite structure of the Customer PIM Suite and whether each of its components is appropriate for financial incentives. In particular, combining Level 1 DER Interconnection with four other measures can dilute the targeted incentive developed in RE02, while the Company has not demonstrated that the other proposed components warrant treatment as PIMs. Our recommendations for each component are summarized in Table G and discussed in greater detail below.

Table G. Recommendations Related to the Customer PIM Suite

Proposed Component	*Recommendation*	*Rationale*
Level 1 DER Interconnection Processing	Retain as a standalone PIM, consistent with RE02 PFD.	Including it in the composite can dilute the targeted incentive because performance on other measures can offset poor interconnection performance.
Digital Customer Engagement	Do not adopt as a PIM. Retain the RE02 PFD Customer Data Engagement Metric as a reporting metric.	The Company has not demonstrated an incremental customer benefit from increasing digital transactions above current levels. The RE02 PFD metric more directly tracks customer use of energy data.
Controllable Average Call Handle Time	Do not adopt as a PIM. Continue to track call center performance through the RE02 PFD Existing Customer Service Metrics.	The proposed measure reflects operational efficiency and customer service performance rather than exemplary

Proposed Component	*Recommendation*	*Rationale*
		performance warranting a shareholder incentive.
Post-Transaction Survey – CSR Attributes	Do not adopt as a PIM. Evaluate customer satisfaction through the broader RE02 PFD Customer Satisfaction Scorecard.	The Company has not demonstrated that performance above its proposed target produces incremental customer outcomes warranting a shareholder incentive.
Average Discount Rate Enrollment Time	Treat initially as a reporting metric.	Timely manual LIDR enrollment is important, but additional performance data are needed to determine whether a PIM is warranted and to establish an appropriate baseline and target.

Q. Please elaborate on your concerns regarding Level 1 DER Interconnection Processing within the Company's proposed Customer PIM Suite.

A. The RE02 PFD identifies Level 1 DER Interconnection as a standalone potential PIM. The Company instead proposes to combine Level 1 DER Interconnection Processing with four other customer service measures in a single composite Customer PIM Suite. The Company explains that it selected this structure because customer experience is multidimensional and argues that a standalone interconnection PIM could place disproportionate emphasis on one customer-facing measure at the expense of other customer outcomes.[80]

We do not believe that concern justifies combining Level 1 DER Interconnection with otherwise distinct customer service measures. The purpose of the Level 1 DER Interconnection PIM is to create a targeted incentive to improve the timeliness and efficiency of the interconnection process. Including that measure within a broader composite can weaken that targeted incentive. The Company confirms that above-target

[80] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-527, Sept. 15, 2026, page 1.

performance on one component can offset below-target performance on another, allowing the Company to avoid a penalty or potentially earn an incentive despite underperformance on an individual measure.[81] For example, strong performance on routine customer service functions can offset flat or worsening DER interconnection performance. Incentivizing improved interconnection performance does not relieve the Company of its obligation to maintain strong performance across its other customer service functions.

We recommend that the Authority retain Level 1 DER Interconnection Processing as a standalone PIM, consistent with the structure developed in RE02, rather than incorporating it into the proposed Customer PIM Suite.

Q. Please elaborate on your concerns regarding the Digital Customer Engagement component of the Company's proposed Customer PIM Suite.

A. The Company proposes to measure digital transactions as a percentage of overall customer transactions, with a target of 92.18 percent based on its 2025 actual performance. The Company explains that digital engagement is already above 90 percent and has reached a point of "digital saturation," such that additional gains will be increasingly difficult. It argues that continued investment is necessary to maintain current levels of digital engagement and that exceeding the proposed target would require significantly greater

[81] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-532, Sept. 15, 2026, pages 1–2.

investment. On that basis, the Company proposes to include the measure in the Customer PIM Suite to encourage continued improvement in customer interactions.[82]

We do not believe the Company has demonstrated that performance above the proposed target warrants a shareholder incentive. The fact that additional gains may be difficult or require additional investment does not, by itself, establish that increasing the share of transactions completed through digital channels above 92.18 percent would produce a distinct incremental benefit for customers. Indeed, the Company acknowledges that opportunities to shift additional customers to digital channels are limited and that some customers will continue to prefer or require non-digital interactions.[83] The Company therefore has not demonstrated why performance above its current level constitutes exemplary performance of the type contemplated by RE02 Design Principle #8.

The Authority did recognize digital customer engagement as a valuable outcome in RE02, but the structure it developed was materially different from the Company's proposal here. The RE02 Customer Data Engagement Metric focuses on whether customers are actually using the digital capabilities enabled by advanced metering infrastructure (AMI), including whether they view their electricity-usage data and enable data sharing with third parties. PURA found that tracking these activities could provide insight into how customers engage with their energy data, help maximize the value of AMI investments, and inform customer

[82] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-528, Sept. 15, 2026, pages 1–2.

[83] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-528, Sept. 15, 2026, pages 1–2.

education and outreach.[84] By contrast, the Company's proposed measure primarily tracks the share of transactions occurring through digital channels. That measure does not provide the same insight into whether customers are meaningfully using energy data or realizing the customer-facing benefits that PURA sought to track in the RE02 PFD.

We recommend that the Authority not adopt Digital Customer Engagement as a PIM on the current record. The Authority should instead retain the Customer Data Engagement Metric developed in the RE02 PFD as a reporting metric as Eversource deploys AMI.

Q. Please elaborate on your concerns regarding the Controllable Average Call Handle Time and Post-Transaction Survey components of the Company's proposed Customer PIM Suite.

A. We do not believe the Company has demonstrated that either measure warrants treatment as a PIM. Both measures may provide useful information about customer service performance, but the record does not demonstrate that above-target performance represents the type of exemplary performance that warrants an additional shareholder incentive. The RE02 PFD similarly treats Average Handle Time as one of several Existing Customer Service Metrics to be reported and evaluates customer satisfaction through a broader Customer Satisfaction Scorecard rather than through a financial incentive.[85]

For Controllable Average Call Handle Time, the Company explains that reductions in hold and post-call work time can lower call center costs, improve answer times, and improve

[84] RE02 PFD, pages 72–74.
[85] RE02 PFD, pages 83–84, 89.

customer satisfaction. Those are legitimate customer service objectives, but they largely reflect efficient management of the Company's call center. The Company has not demonstrated why reducing these times beyond the proposed target represents exemplary performance for which customers should provide an additional financial reward.[86]

We have similar concerns with the Post-Transaction Survey. The proposed target of 8.43 reflects the Company's 2025 actual performance. The Company identifies correlations between customers' ratings of CSR courtesy, friendliness, knowledge, and concern for customer needs and their overall satisfaction with their phone interaction.[87] However, the Company also acknowledges that a customer may not know whether the information provided by the CSR was actually correct.[88] A customer could therefore rate a CSR highly on "knowledge" based on their perception of the interaction without being in a position to assess whether the information they received was accurate. A high survey score therefore does not necessarily demonstrate that the customer received accurate information or that the underlying issue was appropriately resolved. This limits the measure's value as a basis for a financial incentive, as the Company has not demonstrated that performance above the proposed target produces incremental customer benefits sufficient to justify an additional shareholder reward.

[86] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-529, Sept. 15, 2026, pages 1–2.

[87] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-530, Sept. 15, 2026, pp. 1–2. See also Exhibit CLP-CUSTOMER-1, July 14, 2026, pages 38–39.

[88] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-122

We recommend that the Authority not adopt Controllable Average Call Handle Time or the Post-Transaction Survey measure as PIMs. Call center performance should continue to be reported through the Existing Customer Service Metrics, and customer satisfaction should be evaluated through the broader Customer Satisfaction Scorecard developed in RE02.

Q. Please elaborate on your concerns regarding the Average Discount Rate Enrollment Time component of the Company's proposed Customer PIM Suite.

A. The Company proposes to measure the average number of business days required to enroll an eligible customer in the Low-Income Discount Rate (LIDR) after the customer provides qualifying proof of eligibility directly to the Company. The measure applies to applications that require manual review and processing and excludes customers enrolled through Department of Social Services (DSS) data matching or Community Action Agencies.[89]

Timely processing of manual applications is important, particularly for customers newly enrolling in the LIDR who fall outside of the DSS data sharing and for customers moving between discount tiers. However, additional information is needed before establishing a financial incentive. The Company has not historically tracked the data underlying this measure, leaving limited information about current processing times, the extent and frequency of delays, seasonal variation, and resulting customer impacts.[90] Additionally, the two-tiered LIDR placed the customer on the lowest tier and required the customer to

[89] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-531, Sept. 15, 2026, pages 1–2.

[90] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Exhibit CLP-CUSTOMER-1, July 14, 2026, page 40.

contact the Company to move to the higher discount, but recent implementation of the five-tier LIDR might reduce the number of customers contacting the Company to change tiers. Finally, it needs to be clear that the Company, and not Alorica, is fully tasked with processing a customer's financial documents.

Until that record is developed, we recommend that Average Discount Rate Enrollment Time be treated as a reporting metric rather than an incentivized measure. The resulting data can then inform whether a future PIM is warranted and, if so, the appropriate baseline and performance target.

Q. What is missing from the company's proposed portfolio of PIMs?

A. The Company does not propose a Non-Wires Solutions ("NWS") Shared Savings Mechanism, despite the potential value of such a mechanism in encouraging the Company to pursue cost-effective alternatives to traditional infrastructure investments.[91] A shared-savings mechanism can help align utility financial incentives with cost control by allowing the Company to retain a portion of the savings generated when an NWS project avoids or defers a more costly traditional solution, while returning the majority of those savings to customers.[92]

PURA has previously established an NWS framework that includes a shared-savings mechanism under which the EDC may retain 25 percent of net benefits, with 75 percent

[91] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-439, Sept. 11, 2026, pages 1–2.
[92] RE02 PFD, pages 23-24.

accruing to customers.[93] The RE02 PFD considered incorporating that existing mechanism into the Performance Evaluation System.

We recognize that PURA subsequently paused further NWS cycles while it redesigns the NWS process. In April 2026, PURA closed the second NWS cycle without making a screening decision and paused future cycles pending that redesign. At the same time, PURA directed that its existing NWS orders remain in effect and required the Company to continue its Grid Needs and quarterly filings.[94] The ongoing redesign means that the eligibility criteria, process, and implementation details for any future NWS shared-savings mechanism have not yet been finalized.

We therefore recommend that the Authority consider including an NWS shared-savings mechanism within the Performance Evaluation System, informed by the outcome of PURA's ongoing redesign of the NWS process. A future mechanism should preserve the core principle that any reward be tied to demonstrated net benefits from cost-effective alternatives to traditional infrastructure investment, with the majority of resulting savings accruing to customers.

Q. At a high level, what concerns do you have about the portfolio of reporting metrics and scorecards that the Company has proposed?

A. The Company's proposal omits most of the Metrics and Scorecards identified in the RE02 PFD. The Company acknowledges that, of the 38 Metrics, Scorecards, and potential PIMs

[93] RE02 PFD, pages 23-25.
[94] Notice of Docket Closing, Docket No. 26-08-08, Apr. 17, 2026, page 1.

identified in the RE02 PFD, it omitted 22 Reported Metrics and 10 Scorecard Metrics from its proposed Performance Evaluation System. The Company explains that it sought to avoid duplicative reporting, targets that may not account for variability in investment, and measures of outcomes it views as outside its control.[95]

We do not believe those considerations provide a sufficient basis for departing so substantially from the RE02 framework. The RE02 Performance Evaluation System was developed through an extensive stakeholder process, and the PFD assigns Metrics, Scorecards, and PIMs different functions. Metrics provide transparency into utility performance, Scorecards add context for evaluating that performance, and PIMs attach financial consequences to particular outcomes.[96] The RE02 PFD also identifies specific informational benefits associated with individual measures. For example, the Major Storm Reports Metric is intended to improve transparency into customer impacts and support analysis of system resilience and emergency response.[97] A measure can therefore provide important information even where it is not appropriate for a financial incentive.

Where the Company does include measures that overlap with the RE02 PFD, it sometimes narrows or modifies the RE02 design without providing sufficient evidence for doing so. For Cost Efficiency, for example, the Company proposes four reporting measures: Core Operating Expense per Customer, Core Operating Expense per Line Mile, Capital Expense

[95] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-439, Sept. 11, 2026, pages 1–3.

[96] RE02 PFD, pages 7–10.

[97] RE02 PFD, pages 48–49.

per Customer, and Capital Expense per Line Mile. The Company acknowledges that only the two capital-expense measures are the same as measures identified in the RE02 PFD, while the two Core Operating Expense measures are modified versions of RE02's Controllable Opex measures.[98] The RE02 PFD, by contrast, includes a broader Cost Efficiency Scorecard with six sub-metrics covering operating expenditures, controllable Opex, authorized controllable Opex, capital expenditures, capital cost, and total cost, which PURA found would allow stakeholders to evaluate both overall utility costs and individual cost drivers.[99] Similarly, the Company proposes to report Non-Hardship Receivables Greater than 60 Days as a standalone metric, while the RE02 PFD includes accounts receivable over 60 days as one of five sub-metrics within a broader Accounts Receivable and Uncollectibles Scorecard. The Company explains that it selected the 60-day measure because it provides a more timely indicator of delinquency and excludes hardship accounts because collection outcomes for those customers are heavily influenced by legislative and regulatory protections.[100] The RE02 PFD instead uses the broader Scorecard to provide visibility into arrears, accounts receivable, write-offs, and uncollectibles, and specifically found that the 60-day measure provides useful insight when considered within that broader framework.[101]

[98] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-440, Sept. 11, 2026, pages 3–4.

[99] RE02 PFD, pages 16–17.

[100] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-533, Sept. 15, 2026, page 1.

[101] RE02 PFD, pages 99–100.

We recommend that the full suite of Metrics and Scorecards identified in the RE02 PFD serve as the baseline reporting framework in this proceeding. Where the Company proposes to omit or materially modify a measure, that departure should be clearly explained and justified based on the purpose and informational value of the measure before PURA adopts any modification.

Q. What is your recommendation regarding the Cost Efficiency Scorecard developed in the RE02 PFD?

A. We recommend that the Authority require Eversource to implement the Cost Efficiency Scorecard outlined in the RE02 PFD. The Company proposes four individual cost-efficiency reporting measures: Core Operating Expense per Customer, Core Operating Expense per Line Mile, Capital Expense per Customer, and Capital Expense per Line Mile. The Company acknowledges that only the two capital-expense measures are the same as measures identified in the RE02 PFD, while its Core Operating Expense measures modify the RE02 approach.[102]

The RE02 PFD instead developed a broader Cost Efficiency Scorecard comprising six sub-metrics covering operating expenditures, controllable operating expenditures, authorized controllable operating expenditures, capital expenditures, capital cost, and total cost.

[102] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-440, Sept. 11, 2026, pages 3–4.

PURA found that considering these measures together would allow stakeholders to assess both overall utility costs and individual cost drivers over time.[103]

That broader view is particularly important given the cost-containment concerns discussed elsewhere in this testimony and the testimony of OCC's capital witness, Nikhil Balakumar. Looking only at selected operating and capital spending measures may not provide sufficient visibility into whether the Company is improving overall cost efficiency or shifting costs among categories.

We recommend that the Authority include the Cost Efficiency Scorecard as part of Eversource's Performance Evaluation System, rather than replacing it with the Company's narrower set of individual reporting measures.

Q. How could the Performance Evaluation System support greater accountability for management efficiency?

A. The limitations of the management audit discussed above reinforce the value of developing transparent measures of management efficiency over time. Other jurisdictions provide examples of regulators using performance information not only to assess utility costs and operations, but also to inform financial incentives and consequences.

In Iowa, the Utilities Commission evaluates management efficiency using factors including operating and maintenance costs, service quality, officer compensation, bad debt, and management practices that improve service or control costs. If the Commission finds that

[103] RE02 PFD, pages 16–17.

a utility is operating inefficiently, it may reduce the utility's profit or adjust its revenue requirement; extraordinarily efficient management that produces tangible ratepayer benefits may support an upward adjustment.[104]

New York is taking a different but related approach. Beginning in 2027, utilities must report an annual affordability index measuring residential energy burden. The New York Public Service Commission is also required to develop performance-based targets tying CEO and senior-management compensation and ratepayer-funded incentive compensation to the affordability index, and to consider adjustments to utility return on equity based on that metric, excluding factors outside the utility's control.[105]

These examples illustrate how reporting and benchmarking can establish a performance record that may later inform stronger financial incentives or consequences. We recommend that the Authority begin by developing a Management Efficiency reporting Metric, potentially in coordination with the RE02 PFD Cost Efficiency Scorecard. The Metric could track implementation of management-audit recommendations, identified and realized customer savings from those recommendations and other efficiency initiatives, and peer-benchmarked measures of management efficiency.

We recommend that the Authority develop such a reporting Metric initially and use the resulting performance data to evaluate over time whether particular measures warrant

[104] Iowa Code § 476.52; Iowa Admin. Code r. 199-29.3, 29.4

[105] N.Y. Pub. Serv. Law §§ 66(12)(n), 66-x.

elevation to a Scorecard or PIM, or could appropriately inform executive compensation, utility earnings, or other financial incentives or consequences.

Q. What is your response to the Company's position that performance measures should focus on outcomes within the Company's control?

A. The Company states in this proceeding that its proposed Metrics seek to avoid "inclusion of metrics for conduct or outcomes that are beyond the Company's control" and argues that PIMs should be limited to actions within its control.[106] It relies on this rationale in opposing or omitting several measures, including the Peak Demand Scorecard, Beneficial Electrification Metric, Power Restoration After Major Storms Metric, and Environmental Justice Reliability Metric.

That position does not account for the different purposes of PIMs, Scorecards, and Metrics. The RE02 Design Principles impose a control requirement only on potential PIMs. Design Principle #7 provides that a potential PIM should include performance under the EDC's "indirect or direct control." That Design Principle does not apply to Metrics or Scorecards.[107]

The RE02 PFD expressly applies this distinction. For the Environmental Justice Reliability Metric, PURA recognized that storm patterns and other external factors may influence reliability outcomes, but concluded that "direct or indirect utility control is not a prerequisite for the mere reporting of information in the PBR Performance Evaluation

[106] The Connecticut Light and Power Company d/b/a Eversource Energy, Docket No. 26-05-10, Response to OCC Interrogatory OCC-439, Sept. 11, 2026, pages 2–3.
[107] RE02 PFD, pages 10–11.

System." The Authority found that the data would still provide visibility into localized outcomes and could inform future planning and engagement strategies.[108]

PURA reached the same conclusion for Scorecards. In discussing the Equitable AMI Scorecard, the Authority acknowledged that customer participation in AMI-dependent offerings may be influenced by factors outside an EDC's control, but stated that "EDC direct or indirect control is not among the design principles for a Scorecard." The Authority further noted that the EDCs can influence the ease and accessibility of customer participation.[109]

Even for PIMs, RE02 does not require exclusive or direct control. Design Principle #7 expressly includes both direct and indirect control. The EDCs proposed instead that PIMs be limited to activities over which they have "direct or substantial control." PURA declined to adopt that formulation, finding the proposed alternative overly subjective and potentially likely to create future disputes over the definition of "substantial control." The Authority therefore retained the existing direct-or-indirect-control standard.[110]

Accordingly, we recommend that the Authority not permit the Company to exclude RE02 Metrics or Scorecards solely because the underlying outcome is not exclusively within the Company's control. Those measures should remain part of Eversource's Performance

[108] RE02 PFD, page 59.
[109] RE02 PFD, page 52.
[110] RE02 PFD, page 10 n. 19.

Evaluation System where they continue to provide value for transparency, benchmarking, and evaluation.

Q. What recommendations do you have regarding public accessibility of the Performance Evaluation System?

A. An important objective of the Performance Evaluation System is to improve transparency into utility performance and provide information that can inform future regulatory decisions. As discussed above, Metrics and Scorecards serve an important role in tracking performance, identifying trends, and evaluating outcomes, even where they are not tied to financial incentives. However, realizing those benefits also requires that the reported information be readily accessible and understandable to stakeholders and the public.

The RE02 PFD recognizes this need and envisions a publicly accessible PBR Dashboard that presents Metrics, Scorecards, and PIMs in a clear, visually accessible format, with explanatory information to support interpretation. OCC has supported this approach throughout RE02, emphasizing the importance of a user-friendly dashboard that allows stakeholders to meaningfully engage with utility performance data. OCC also identified Hawaiian Electric's PBR dashboard as a potential model.[111]

A centralized dashboard would allow customers, advocates, and other stakeholders to more easily evaluate utility performance over time and against relevant benchmarks, without having to compile information from multiple regulatory filings. It could also help identify

[111] RE02 PFD, pages 104–105.

areas where performance is improving or deteriorating and support more informed participation in future regulatory proceedings.

The RE02 PFD further proposes that PURA develop and maintain the dashboard, while EDCs remain responsible for submitting complete and timely performance data and accompanying explanatory narratives.[112] We support this division of responsibilities, which would provide for a centralized presentation of utility performance while maintaining the Company's reporting obligations.

We recommend that the Authority carry forward the publicly accessible PBR Dashboard envisioned in the RE02 PFD as part of implementing the Performance Evaluation System. The dashboard should present all adopted Metrics, Scorecards, and PIMs, including relevant historical trends and benchmarks, in a format that is accessible and understandable to the public. We further recommend that the Authority solicit stakeholder input on the dashboard's design and use cases, consistent with the approach outlined in the RE02 PFD.

[112] RE02 PFD, page 105.

V. STORM COST RECOVERY

Q. What is the purpose of this section?

A. The purpose of this section is to identify the potential risks to ratepayers associated with the Company's proposed changes to the storm cost recovery framework due to lack of cost containment incentives, respond in a preliminary manner to the Authority's alternative framework and menu of alternative ideas as described in Attachment 1 to the Notice for Technical Meeting on November 2nd, and to outline additional ideas and considerations for the Authority and other parties' consideration in the workshop and throughout the proceeding. Final positions of this panel may also shift as a result of the input in the Technical Meeting.

Q. Summarize the changes that the Company proposes to the cost recovery framework for storm costs relative to the pre-existing framework?

A. The Company proposes several changes to the recovery of storm costs in base rates, as well as the recovery of storm costs that exceed the reserves funded through base rate contributions. For ease of reference, we summarize here the primary differences between the business-as-usual approach (i.e. the existing framework) that are most relevant for the concerns we highlight in later questions:

a. **Eligibility criteria for what constitutes a catastrophic storm**: The Company proposes to increase the catastrophic storm cost threshold from $4 million per event to $5.4 million per event. [113]

[113] Exhibit CLP-ELP-1, p. 121.

b. **Funding mechanism – base rate reserves**: First, the Company proposes to "establish the customer contribution to the catastrophic storm reserve in base rates at $60 million per year."[114] Second, the Company proposes to "establish a level of pre-staging reserve funding in base rates at $4 million per year."[115]

c. **Funding mechanism for and prudence review of storm costs in excess of base rate reserves (referred to as "excess storm costs")**: The Company proposes to increase the frequency of prudence reviews for excess storm costs from rate cases or other irregular intervals to occur in an annual Storm Cost Recovery Adjustment Factor ("SCRAF") proceeding.[116]

d. **Carrying Charges on excess storm costs**: The Company proposes to alter the current framework and apply carrying charges from the date of cost occurrence on the net balance of catastrophic storm and prestaging storm funds for storms after March 2025 (i.e., carrying charges would be incurred prior to prudence determination), whereas previously, carrying charges were allowed only on a prospective basis (i.e., after a prudence determination).

Q. What are your concerns with the Company's proposed changes to the cost recovery framework for storm costs?

A. When looked at as a whole, the Company's proposal works in favor of the Company and against ratepayers by creating a weak and limited incentive for the Company to be cost

[114] *Id*.
[115] *Id*.
[116] *Id*.

disciplined in its storm preparedness and response activities, and providing the Company carrying charges before a prudency determination.

First, by remaining anchored to a catastrophic storm eligibility threshold that is contingent solely on the costs incurred per event, the Company's proposal perpetuates the Company's incentive to spend more in response to storms, rather than cost-effectively planning for and addressing potential outage events.

Second, the Company's proposal attempts to award carrying charges before the Authority makes a prudency determination. The proposal, however, seeks annual prudence reviews, which will shorten the period between when excess storm costs are incurred and when they will be recovered from ratepayers (i.e., the regulatory lag will be lessened). Therefore, the Company's proposal to apply carrying charges from the date of cost occurrence is not only contrary to the holding in Docket No. 25-12-13, which followed the historical practice of permitting carrying costs only after a finding of prudence[117], but is even less compelling given the short time between cost incurrence and recovery.

We find the Company makes no compelling argument for continuing to determine catastrophic storms based solely on a monetary threshold and for abandoning the practice of allowing only prospective carrying costs to be incurred upon a prudence determination.

Q. Please elaborate on the cost-efficiency incentive concerns with the Company's proposed approach to storm costs.

[117] Docket No. 25-12-13, Decision, Public Utilities Regulatory Authority, July 29, 2026, pages 120-136

A. The Company's proposed approach to management of storm costs, both non-catastrophic and catastrophic, will offer little to no cost-efficiency incentive.

Basing the catastrophic storm eligibility solely on a monetary threshold creates an incentive to spend more on storms. This is particularly true for storm events for which the total costs are estimated to be close to the proposed $5.4 million threshold; spending more in those circumstances increases the likelihood that the total costs associated with the storm event will meet the eligibility criteria to be considered catastrophic.

In a scenario where the accumulated balance of non-catastrophic storm events is approaching or has already exceeded the amount of non-catastrophic storm revenues authorized in base rates, the motivation to increase spending on individual storm events would be higher. Because only excess storm costs for catastrophic storms and pre-staging events are eligible for SCRAF, it would be a strong motivator for storms "on the cusp" of being catastrophic to be deemed catastrophic to increase the Company's likelihood of being "made whole".

Additionally, annual SCRAF prudence reviews will shorten the period between when excess storm costs are incurred and when they will be recovered from ratepayers (i.e., the regulatory lag will be lessened). Regulatory lag is a feature of ratemaking that can increase the cost-efficiency incentive, so lessening it will further reduce the Company's incentives to contain catastrophic storm costs.

Q. What additional alternatives for the Authority's consideration would you add to those offered for consideration in Attachment 1 to the Notice for Technical Meeting filed on October 7 ("Attachment 1")?[118]

A. We prefer to delay making definitive recommendations regarding changes to the storm cost recovery framework at this time, as we anticipate the discussion in the technical meeting and related analysis will be beneficial. However, we offer a modified alternative to expand upon the menu of options identified by the Authority in Attachment 1 of the Notice for Technical Meeting, along with preliminary considerations around how this alternative may affect utility incentives to prepare for and respond to storms in a cost-disciplined manner. We also identify aspects of alternative storm cost recovery proposals that have been used in other states, but note our concerns with those alternatives as topics for further consideration.

Alternative option:

The Authority could implement a storm evaluation on a regular cadence with multi-pronged criteria for what constitutes a major storm and continued reserve funding.

First, the Authority could evaluate all major storms on an annual basis as part of the rate adjustment mechanism ("RAM") proceeding. The Authority could require Eversource to file its storm costs and substantiation for the most recent full year for which documentation is available at the outset of the RAM proceeding. Stakeholders would then evaluate the evidence filed as part of the Authority's prudency review and the Authority could include

[118] Docket No. 26-05-10, Notice of Technical Meeting on November 2, 2026, Attachment 1, October 7, 2026, Public Utilities Regulatory Authority of Connecticut

a prudency determination as part of its decision in the second phase of the RAM docket. The adjustments associated with that prudency finding could then go into effect with the September RAM adjustments, eliminating any delay between the prudency determination and recovery, and thus reducing carrying costs.

Second, the Authority could adopt a two-pronged criteria to evaluate major storms. For a storm to qualify as a major storm, the Authority could require that a storm meet both a monetary threshold (as currently required) and an additional, objective, impact-based eligibility criteria. For example, as the Authority suggested in its Notice of Technical Meeting, and as recommended by OCC Witness Balakumar, an objective, impact-based criteria could be the IEEE Major Event Day methodology. Alternatively, the objective criteria could be the count of customers whose service was interrupted by an event.[119]

The benefit of employing objective eligibility criteria for qualifying as a catastrophic storm event, in addition to a cost-based threshold, is that the Company would not be able to increase spending during a storm event to increase the likelihood that it will qualify as a catastrophic storm. To echo a point made by Witness Balakumar, a dollar-based threshold in isolation increases both the event cost and the likelihood that the storm event will qualify for extraordinary recovery, even when the forecasted damage does not occur. All else being

[119] In New Hampshire, an event qualifies as a major storms if either 10% of more of Eversource's retail customers lose power and there are more than 200 reported troubles, or, more than 300 reported troubles, regardless of the number of customers experiencing outages. Troubles can be either an outage or a non-outage incident (e.g., damage to the system that requires inspection or repair). *See* Docket No. DE 25-021, Petition for Review of Storm Expenses, Joint Rebuttal Testimony of O'Brien, Dickie, and Desautels, New Hampshire Public Utilities Commission, January 7, 2026, pages 9-12.

equal, additional criteria beyond the control or influence of the utility will likely yield fewer catastrophic storm events eligible for preferential cost recovery.[120]

Using the evidence in the present docket, if the IEEE Major Event Day methodology were an additional filter for catastrophic storm qualification, five of the 14 catastrophic storms events for which Eversource is seeking recovery in this proceeding would not be defined as catastrophic, and therefore, would not be eligible for supplemental cost recovery.[121] Therefore, coupling objective criteria with a monetary threshold may reduce the number of catastrophic storms in any given year.

Third, the Authority may consider setting additional reporting requirements as part of the annual review process. Such additional reporting requirements could include, for example:

- For each catastrophic storm event, the Authority could require Eversource to submit a comparison of forecasted (i) trouble spots, (ii) customer outages, and (iii) crew needs to actual utilization and explain the variances.
- For each catastrophic storm event, the Authority could require Eversource to provide a single Excel table that provides the following high-level data: daily SAIDI, SAIFI, CAIDI, CMI, customers interrupted, peak customers out, trouble spots, crew counts, pre-staged crews, actual crews used versus the number of crews

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We use the term preferential cost recovery to reference that fact that once the catastrophic storm reserves are depleted, supplemental recovery of excess catastrophic event costs, if deemed prudent, have historically received prospective carrying charges, equivalent to the Company's WACC. If a storm event does not meet the criteria for catastrophic event, then the costs must be funded by base rates, and risks eroding utility earnings.

[121] OCC-851

on standby and/or remained at area work centers, standby hours, travel time, lodging/meals, and total cost, and compare it to the same data for previous storms.

- The Company could be required to submit storm hardening and vegetation management expenses incurred during the preceding 12 months and demonstrate how these efforts decreased outages or storm impacts. Requiring this information could help PURA evaluate both the efficacy of the vegetation management program as well as ensure excess storm cost recovery is appropriate.
- Additionally, the Authority could also require the Company to provide benchmarking and comparison of the Company's storm costs to other similarly-situated utilities (such as Rhode Island utilities) or the Eversource operating companies in neighboring states.

Any of these options could help the Authority and parties to future proceedings ensure that Eversource did not recover for excessive storm costs.

Likewise, to assist with the prompt review of storms in the annual RAM proceeding, the Authority could issue more defined guidance on permitted storm costs. For example, in Docket No. 25-12-13, parties disputed topics such as excessive travel time, vegetation costs, dock crews, appropriate staffing levels, standby billing, and a variety of other topics.[122]

[122] After noting in the Decision in Docket No. 25-12-13 that Eversource has significantly increased the number of outside vendors it secures for storms, the Authority stated that it would consider in this rate case the issue of storm overstaffing. Additional criteria and guidance is likely necessary to result in a change in how Eversource will staff storms relative to the past since it has received recovery for past storms at the higher staffing levels. *See* Docket No. 25-12-13, Decision, page 74.

Clearer guidance on permitted storm costs would allow more expedient annual storm reviews.

Q. Please describe and evaluate other alternatives.

A. Solely changing the materiality threshold: In Docket No. 21-05-15RE01, the Authority and parties considered increasing the materiality threshold for catastrophic storms from $4 million to 1% of annual base distribution revenues as a threshold for incremental costs related to a storm to be recovered.[123] The rationale was that a 1% materiality threshold would "ensure that only significant but not routine events qualify, striking a balance between cost recovery and avoiding automatic off-ramp triggers," associated with a multiyear rate plan.[124]

A 1% materiality threshold in this case would be equal to $19,219,230.[125] This constitutes a 3.6x increase relative to the Company's proposed $5.4 million threshold. Therefore, employing a 1% materiality threshold would require a recalculation of the level of non-catastrophic storm costs that must be established in base distribution rates.

A downside of *only* increasing the materiality threshold to qualify for incremental storm cost relief (i.e., not also incorporating an impact-based criteria) is that the threshold is still based solely on costs – a measure partially within the influence of the utility. As such, we

123 Docket No. 25-05-15RE01, Revised Straw Proposal, page 32.
124 Docket No. 25-05-15RE01, Proposed Final Decision, page 28.
125 OCC-434

also encourage the Authority to consider adopting objective, impact-based eligibility criteria.

Creating a storm reserve for all storm and pre-staging costs: Other jurisdictions have evaluated creating a storm reserve for *all* storm and pre-staging costs in base rates equal to a normalized average of the last four or five years of actual, prudently incurred storm costs. Costs related to extraordinary storms, meeting a combination of cost- and impact-based criteria (such as those mentioned above), could be eligible for recovery pending a prudence review.

While this alternative would create a strong incentive for cost-discipline for non-extraordinary storms, the primary concern with this approach is that it would substantially increase base rates compared to the amounts included in the test year for non-catastrophic events, and in the catastrophic and pre-staging reserves.

Additionally, it is important to acknowledge that the immediate four- to five-year historical normalized average of non-extraordinary storm events was incurred under a framework that risks incentivizing the Company to spend more on storm events to qualify as catastrophic. This could result in a normalized average that is excessive relative to what would otherwise be necessary if the Company had been operating within a framework with strong cost-efficiency incentives.

Q. What are the benefits of increasing the catastrophic storm eligibility threshold and adopting additional impact-based eligibility criteria?

A. If PURA were to increase the threshold for catastrophic storms and establish additional impact-based criteria, it could have the following implications:

The appropriate reserve level in base rates for non-catastrophic storms would necessarily increase for reasons Eversource cites in OCC-434. However, catastrophic storm reserves (proposed at $60M) could either reduce or remain level (to reduce the likelihood that supplemental recovery would be necessary).

Assuming that, all else being equal, catastrophic storms would be less frequent by virtue of a higher threshold and additional impact-based criteria, and a greater proportion of storm events would be covered by revenues in base rates, supplemental recovery (either through the Company's proposed SCRAF or other mechanisms) might be less frequent.

This would result in the amount recovered through the prudency review being less because a greater proportion of storm events would be "covered" by base rates, making the cost-efficiency incentive stronger for the utility to be cost disciplined in its preparation for and response to storm events going forward. Future rate cases will benefit from a review of historical storm costs that were subject to a strong cost-efficiency incentive.

The considerations above are not a substitute for a rate impact analysis, which should be conducted to support the selection of an alternative storm cost recovery framework. The extent to which these benefits materialize would be subject to a variety of factors including but not limited to the choice of additional threshold criteria, the level of a cost-based

threshold, if one persists, and the severity of weather and events in the future, which cannot be predicted.

Q. Do you recommend that PURA adopt any of the alternative approaches offered above?

A. At this stage, we are not offering a definitive recommendation. We offer the options described above to expand upon the Authority's consideration in the November 2nd Technical Meeting and within this proceeding. More information from the Technical Meeting is necessary to inform a final recommendation.

Q. What recommendations do you have for PURA regarding the storm cost recovery framework?

A. We encourage the Authority to create a storm cost recovery framework that: occurs on a regular cadence; diminishes carrying costs by allowing quick recovery; and contains additional guardrails and reporting requirements when reviewing petitions for supplemental storm cost recovery to support an evaluation as to whether the incurred costs were incurred in a cost-disciplined manner.

Q. Does this conclude your testimony?

A. Yes.