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 Nikhil Balakumar

On Behalf of Connecticut Office of Consumer Counsel

October 21, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q1 Please state your name, business address, and position.

A. My name is Nikhil Balakumar. My business address is 41 29th Avenue, Venice, California 90291. I am the Founder & CEO at Eclipse Energy Partners ("Eclipse").

Q2 Please describe Eclipse.

A. Eclipse is a consulting and advisory firm that primarily supports consumer advocates' offices, state energy offices, and environmental non-governmental organizations on a broad set of regulatory issues including capital investment and planning, interconnection, distribution system planning, grid operations, data access, flexibility markets, and grid modernization technology as it relates to distributed energy resource ("DER") integration and electrification.

Q3 Please describe your professional experience before beginning your current position at Eclipse.

A. My expertise is grounded in a diverse set of perspectives representing public interest groups, utility and DER technology companies in over ten different jurisdictions. Prior to Eclipse, I led Strategen's grid modernization practice for nearly two years, supporting state energy offices, consumer advocates, and non-governmental organizations. I also served as Head of Market Development for the Eastern region at Utilidata, where I advocated for regulatory policy and supported utility commercial deals that would enable utility grid modernization investments to improve the visibility and control of the distribution system and thus enable greater integration and utilization of DERs. I served as Principal at the Greentel Group where I advocated for data access policies across the country. I also led the Research & Development group at Incentive Technology Group

where we developed a residential DER platform to empower customers to make clean energy investments.

Finally, through these collective experiences, I have worked on regulatory issues across the country, including Massachusetts, Maine, Connecticut, Rhode Island, New York, New Jersey, Maryland, Michigan, Illinois, Texas, and California. I have a Bachelor of Science in Management & Entrepreneurship from the University of Maryland, Robert H. Smith School of Business. My resume is included as Attachment 1.

Q4 Have you previously provided evidence before the Connecticut Public Utilities Regulatory Authority (PURA)?

A. No.

Q5 Have you previously provided testimony in other jurisdictions on Eversource Energy or topics like those you are testifying to in this case?

A. Yes. I have significant experience reviewing and testifying on issues related to Eversource Energy ("Company" or "Eversource") in Massachusetts on behalf of the Massachusetts's ratepayer advocacy division within the Office of the Attorney General since 2024. Specifically, I have testified regarding the Company's Electric Sector Modernization Plans[1], 2025 Capital Investment Proposals[2], and the Long-term System Planning Process[3]. Moreover, I have testified before state utility regulatory bodies in Maine, North Carolina, Illinois and Maryland. I testified in Maine for the Governor's Energy Office in the Central Maine Power Company rate case, in North Carolina on behalf of the Attorney General's Office, in Illinois on behalf of Joint Non-governmental Organizations regarding Ameren Illinois and Commonwealth Edison's 2024 and 2026 Multi-Year Integrated grid

[1] D.P.U. 24-10/-11/-12.
[2] D.P.U. 25-30, 25-81, 25-83.
[3] D.P.U. 25-30.

plans and in Maryland on behalf of the Maryland Energy Administration on Pepco[4] and Baltimore Gas & Electric's[5] 2025 and 2026 rate cases.

Q6 On whose behalf are you providing evidence in this case?

A. I am testifying on behalf of the Connecticut Office of Consumer Counsel ("OCC").

Q7 What is the purpose of your testimony and how it organized?

A. The purpose of my testimony addresses several components as described below:

First, I review the Company's proposed Five-Year Targeted System Performance Plan ("TSP"). Per OCC Witnesses Wilson and Tully, OCC recommends that the Authority deny the Company's Performance-Based Multi-Year Rate Plan ("PBMRP") proposal and only approve a one-year rate plan in this docket. Thus, my testimony: a) critiques the Company's TSP proposal from an investment strategy perspective; and b) recommends an alternative, optimized TSP proposal if PURA intends to approve the TSP with modifications.

Second, I review the Company's Advanced Metering Infrastructure ("AMI") proposal to determine its reasonableness including whether there is a sufficient roadmap to rapidly and iteratively maximize the benefits from this proposed investment.

Third, I review the Company's in-service investments since 2017 for prudency.

[4] Case No. 9820.
[5] Case No. 9820.

Finally, I review the Company's request for storm cost recovery and provide suggestions regarding the current request and how to address storm cost recovery in the future.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q8 Please summarize your conclusions and recommendations regarding the Company's proposed TSP.

A. My recommendations are as follows:

Sustained Plan

PURA should neither accept the Sustained tier as the minimum investment level nor approve it as a five-year budget. The Company has not demonstrated that its proposed spending above historical levels is cost-effective or affordable nor has it adequately demonstrated the need for the proposed capacity investments and transformer replacement volumes contained within the Sustained tier.

If PURA authorizes any forecast capital spending under the Sustained tier, it should:

- Historical Baseline: Require the Company to establish the historical spending baseline prescribed by the Reliability Framework, escalated as directed by PURA, and justify any spending above that baseline through documented project- or program-level need and quantified benefits.

- Substation Capacity: Exclude from forecast-based recovery projects lacking an approved scope, cost estimate, in-service date, or documented non-wires solutions (NWS) screening. Such costs should be considered only after the required information is provided.

- Line capacity: Require documented NWS screening results or justified exclusions for each project, using updated battery cost assumptions rather than the $2 million/MWh assumption previously rejected by PURA.

- Transformer replacements: Limit replacements to transformers with documented poor condition, along with the failed Stevenson 14A unit, supported by unit-level condition assessments, evaluated alternatives, and cost estimates.

- New Customer investments: Require the Company to substantiate the proposed budget with a documented forecast of customer service requests.

These recommendations are consistent with OCC Witnesses Wilson's and Tully's recommendation that PURA reject the TSP and use the IDSP process to inform any future multi-year capital investment plan.

Targeted System Performance

PURA should not approve the $374 million in additional revenue requested to implement the Targeted System Performance tier. The Company calls the Sustained tier the minimum needed to maintain reliability, so based on their categorization, the entire increment is discretionary. Before any TSP-tier resiliency spending is approved, the Company should provide a benefit-cost analysis under PURA's resilience framework, including a separate estimate of avoided storm restoration costs.

Advancing the Grid

PURA should not approve $770 million in additional revenue requested to implement the Advancing the Grid tier, as the Company has not sufficiently quantified incremental benefits beyond the sustained tier.

PURA should reject the Company's approach to "advancing the grid" and if it approves a multi-year framework and approves a version of the TSP, the approach to both should instead include a coordinated set of investments grounded in key goals and associated use cases to realize such goals. Grid modernization should serve the purpose of enabling a flexible, optimized, cost-effective grid that maximizes the utilization of the system leading to the deferral and/or efficient buildout of infrastructure. Fostering and scaling a robust market for the cost-effective integration and utilization of DERs is central to achieving this vision. My recommendations below outline such a coordinated approach.

Distributed Energy Resource Management System (DERMS)

If PURA moves ahead with a multi-year rate plan and approves a version of the TSP to more cost-effectively promote grid-modernization, I recommend the proposed DERMS investment be approved conditional on the development of an iterative roadmap with annual updates that details the following:

- How and when dynamic flexible interconnection, DER distribution grid services and DER bulk power services will be demonstrated and scaled as further described below.

- A broader strategy for how DERMS locational deployment will be prioritized across the company's service territory to balance the implementation of various use cases as further described above.

- Details on how various grid modernization investments will be coordinated with DERMS including advanced planning & forecasting tools and AMI.

Grid Compensation Fund

If PURA moves ahead with a multi-year rate plan and approves a version of the TSP, I recommend the proposed Grid Compensation Fund be approved conditional on the following:

- The Company commits to evaluating the grid services procurement process and allocating funds to testing a flexibility market platform.

- The Company commits to a midpoint milestone (i.e. two years into implementation) where they will work with stakeholders to iterate on and develop a scalable grid services framework inclusive of an updated compensations framework.

- The Company consolidates its filings into a single annual filing to serve as a broader update on the Company's progress towards a flexibility first approach that addresses DERMS, dynamic flexible interconnection and DER distribution grid services.

Advanced Forecasting Tools & Circuit Planning Capabilities

If PURA moves ahead with a multi-year rate plan and approves a version of the TSP, I recommend the proposed Advancing Forecasting Tools & Circuit Planning Capabilities be approved conditional on the following:

- The Company begins advanced forecasting in an iterative manner once tools are available and be informed by locations identified as part of implementing dynamic flexible interconnection, the Grid Compensation Fund and the DERMS rollout.

- The Company will coordinate its deployment with AMI such that AMI prioritizes deployment at locations that can support advanced forecasting.

Shared Hosting for Advancement of Renewable Energy (SHARE)

I strongly recommend PURA reject the Company's proposal related to SHARE and explicitly require it first to leverage dynamic flexible interconnection in areas of high DER development with limited hosting capacity, consistent with PURA's recent decision in Docket 25-01-27. If PURA is interested in establishing a proactive planning framework, I recommend that a separate stakeholder process be established to develop such a framework and incorporate lessons learned from other jurisdictions.

Q9 Please summarize your conclusions and recommendations regarding the Company's proposed AMI investment.

A. I recommend the Company's proposed AMI investment be approved conditional on the following requirements:

- The Company must: a) provide access to raw meter usage data and enrolled programs; and b) include and publish additional metrics to report on platform performance as described above.

- The Company must commit to leveraging this platform as a one stop shop for future data access and propose solutions to integrate system and rates/tariff information into such platform.

- The Company must iteratively enable 8760 profiles at feeders and substations as sufficient AMI is deployed at specific regions.

- The Company must use the locations it identified to prioritize dynamic flexible interconnection, the DER compensation fund, and DERMS deployment to inform where AMI should first be strategically deployed and enable 8760 profiles in these regions.

- The Company must propose a concrete distributed intelligence pilot with specific use cases within one year of approval of the AMI deployment.

- The Company must include an evaluation of the potential of AMI to defer or replace sensor investments and report as part of investigating how AMI can support real-time operations and report on the progress of this investigation as part of ongoing AMI updates.

Q10 Please summarize your conclusions and recommendations regarding the Company's in-service investments.

A. I recommend that PURA:

- Direct-buried cable: Disallow about $26.5 million of 2022–2023 replacement costs above the 2019–2021 unit cost, net of demonstrated inflation, absent a contemporaneous analysis supporting full replacement.

- Capacity additions: Disallow capacity additions where the Company fails, by the close of the record, to prove prudence of these investments by providing the contemporaneous evaluation of non-wires alternatives, the load forecast and the authorization documents for each Peak Load/Capacity project placed in service from 2023 through 2025 ($145.4 million), do not find a project prudent where the Company cannot make that showing, and disallow the cost above the least-cost alternative where one was available.

- Resiliency additions: Require before-and-after storm performance data for the resiliency programs and weigh the absence of measured benefits in deciding whether resiliency additions placed in service after 2020 were prudently incurred.

- Areas pending Company data: OCC is requesting additional data on capitalized vegetation work, the proactive direct-buried cable replacement

program, capitalized storm restoration costs from the 2018–2023 storms, AMR meter additions, and the measured benefits of the resiliency programs. I will provide my recommendations on these additions and whether they should be included in rate base in full or in part in surrebuttal testimony.

- Planned plant additions: Include in rate base only plant additions that are completed, in service and documented before the close of the record and exclude all forecasted plant additions that are not in service and used and useful. Our current estimate is that of the $847.8 million of interim period plant the Company requested from January 2026 through June 2028 approximately $202.5 million will still be forecasted plant at the close of the record and therefore should not be included in rate base, as well as the full $664.9 million requested for the Rate Year.

These recommendations do not deny the Company recovery of prudent investment. They remove an amount the record shows was not justified, defer a finding where the record does not yet contain the information needed to adequately assess prudency, and sets forth what OCC needs to evaluate the Company's forward-looking capital requests, including the TSP.

Q11 Please summarize your conclusions and recommendations regarding the Company's storm recovery investments.

A. Storm recovery should be impact-based, not exclusively spend-based. Meeting the monetary threshold alone should not make a storm "catastrophic." I recommend that PURA:

- Add to the monetary threshold an impact-based test, using the Connecticut Major Storm criterion and IEEE 1366 Major Event Days or other impact-based criteria, to decide which events qualify for extraordinary storm recovery.

- When seeking recovery for crew levels that exceed benchmarks for each ELM event level in the ERP, require the Company to demonstrate the reasons at the time and justify the excess, beyond the forecast alone, tied to individual

forecasted trouble spots. The Company may exceed a benchmark when conditions require but should demonstrate the reasons at the time and justify the excess, beyond the forecast alone, when seeking recovery.

- Disallow recovery of, at minimum, the portion of the $62.0 million requested for storms MS24A, MS24B, MS24C, MS24D, MS24H, and MS24K that exceeds established spending benchmarks. Consistent with OCC's prior recommendation, PURA should disallow costs above these benchmarks, particularly where the Company has not demonstrated that its storm staging and resource decisions were prudent. This proceeding should establish clear guardrails to prevent excessive storm spending in the future. Customers should pay for prudent storm preparation and restoration, not excessive pre-staging or costs driven by overstated forecasts without demonstrated benefits. For these six events, the Company acknowledged that forecasts overstated storm severity, contributing to higher costs. Our final disallowance on these storms will depend on the subsequent information provided by the Company in the record.

- Reject the Company's storm-related programs and system hardening investments until the Company demonstrates how it will improve its storm response and reduce storm costs for customers. At a minimum, the Company should reconcile its storm forecasts with actual outcomes and establish measurable performance metrics for storm response costs, forecast accuracy, crew staging, restoration time and lessons learned from each event, using the storm costs in this filing as a baseline for future accountability.

III. TARGETED SYSTEM PERFORMANCE PLAN

A. Purpose and Overview

Q12 What is the purpose of this portion of your testimony?

A. This portion of my testimony addresses the Company's proposed five-year TSP Plan for 2027 through 2031. I rely on the testimony and exhibits of the Company's TSP panel and the Company's responses to OCC's interrogatories. My testimony examines whether the Company has shown that the plan is needed, sufficiently developed to fund, and the lowest reasonable cost way to meet system needs, including whether the Company evaluated non-wires solutions before seeking funding for capacity projects. It supports the recommendation of OCC Witnesses Wilson and Tully that PURA reject the TSP as a basis to establish a multi-year capital plan and use the Integrated Distribution System Planning ("IDSP") process to inform any future multi-year capital plan.[6]

Q13 Please summarize the purpose of the proposed TSP.

A. The TSP should serve as a thoughtful and data-driven strategic plan for the distribution system that deliberately and steadily progresses toward a vision for the future state, while balancing performance and affordability for customers and covers the planning horizon for operations and investment in the Company's distribution system over the timeframe of January 1, 2027 through December 31, 2031.[7] Specifically, the TSP describes a broader approach to maintain or improve performance with the focus on six goals including (1) safety, (2) high levels of reliability, (3) sufficient capacity, (4) resiliency, (5) accommodating DERs, (5) a transformation unto a dynamic modern grid and (6) affordability.[8]

[6] Direct Testimony of OCC Witnesses Wilson and Tully.
[7] Exhibit CLP-TSP-1, at 16.
[8] Exhibit CLP-TSP-1, at 15.

The Company further elaborates on its goals of DERs and a dynamic modern grid stating: (a) the system must be positioned to accommodate interconnected DER to allow for renewable generation of electric power, as well as support of the distribution system where those facilities can be leveraged as distribution assets to defer traditional electric delivery infrastructure buildout; and (b) over the next ten years and beyond, the system must be transformed into a dynamic modern grid, leveraging cutting-edge technologies, equipment and controls, combined with innovative engineering strategies and tools to increase functionality, capture efficiencies and meet the challenges of a modern society with virtually zero tolerance for electric interruptions.[9]

Q14 Please elaborate on how the proposed TSP is structured.

A. The Company has structured three levels of potential investment for the CL&P distribution system over the next five years:[10]

- **Sustained:** The Company states the baseline investment plan is the minimum level of investment needed to maintain reliability performance; meet regulatory obligations; and maintain asset health and foundational system planning capacity for safety and reliable operations.

- **Targeted System Performance:** The Company states this is a supplementary tier of investment directed at achieving an escalating level of asset-health replacements and enhanced reliability performance, while also commencing a system resiliency initiative.

- **Advancing the Grid:** The Company is presenting an investment plan that would build on the 5-Year TSP Plan over the longer term, accounting for investments related to state policy initiatives and higher standards of

[9] Exhibit CLP-TSP-1, at 15-16.
[10] Exhibit CLP-TSP-1, at 17-18.

innovation and software tools including those to support DER integration, clean-energy advancement and advancing the grid toward modernization.

Q15 What is your understanding of the Company's request?

A. In the Targeted System Performance tier, the Company asks PURA to approve $3.985 billion of capital spending over five years, from 2027 through 2031. This includes $3.611 billion in the Sustained tier, which increases from $667 million in 2027 to $757 million in 2031.[11] The Company describes the sustained tier as "the minimum level of investment needed to maintain reliability performance; meet regulatory obligations; and maintain asset health and foundational system planning capacity for safety and reliable operations."[12] The second tier, Targeted System Performance, adds $374 million, including $155.0 million for resilience, $143.3 million for asset health, and $75.8 million for enhanced reliability.[13] In this second tier, the Company also proposes approximately $71 million of incremental O&M, including a $38 million Grid Services Compensation Fund.[14] The third tier, Advancing the Grid, builds off of the first two tiers then adds an additional $396 million for a total of $4.381 billion. Under all three tiers, vegetation management spending would increase from $59 million to $91 million a year beginning in 2028.[15]

The Company presents the three tiers as "budget options" to allow PURA to consider the appropriate balance between system needs and customer costs[16], while recommending the second tier, a.k.a. the Targeted System Performance tier.[17] However, if PURA considers the proposed TSP, it should evaluate the

[11] Exh. CLP-TSP-3 at 10.
[12] Exh. CLP-TSP-1 at 17.
[13] Response to OCC-809.
[14] Exh. CLP-TSP-3 at 43.
[15] *Id.* at 11.
[16] Exh. CLP-TSP-1 at 47.
[17] Exh. CLP-TSP-3 at 7, 11.

proposal in the context of what the most strategic and cost-effective investments should be approved - not artificially created tiers.

Q16 What would PURA be approving if it adopted one of the tiers?

A. PURA should be approving more than a planning concept as Eversource has proposed. The Company proposes to recover TSP capital through the F-Factor under its proposed Performance-Based Multi-Year Rate Plan ("PBMRP"), which the Company describes as "tethered to the planned capital investment plan described in the TSP Plan."[18] The Company states that the F-Factor would provide "revenue support for ongoing capital expenditures," subject to "periodic and ongoing prudence reviews," a cap, and "downward-only reconciliation in the event actual overall plant-in-service is less than the capital expenditure forecast."[19] The reconciliation compares total plant in service to the total forecast. It does not compare individual projects or programs. Funds forecasted for a project that is deferred or cancelled can be spent on other work without a refund. The Company also states that PURA would make its prudence determination on planned plant additions "in the next rate case at such time that those projects are placed in-service."[20]

Approval of a tier would therefore place five years of forecast capital into rates before many of the projects have a defined scope, cost estimate, in-service date or alternatives analysis.

Q17 What is your primary position on the TSP?

A. In conjunction with OCC Witnesses Wilson and Tully, we recommend that the Authority deny the Company's PBMRP proposal and only approve a one-year rate plan in this docket. I agree with the concerns Ms. Wilson and Mr. Tully have

[18] Exh. CLP-ADDITIONS-1 at 54.
[19] Response to OCC-579(a)(ii).
[20] Exh. CLP-ADDITIONS-1 at 54.

outlined regarding the lack of in-depth capital planning that would protect Eversource customers from unnecessary costs in a multi-year rate plan tied to a forward-looking capital plan.

Q18 If PURA intends to approve a version of the TSP, what is your position?

A. The Company's proposal represents a "business-as-usual" approach focused on traditional capital expenditures and lacks a sense of urgency to scale up grid modernization investments that will accelerate the transition towards a more dynamic and cost-effective system. The Company itself states that the third tier of investment (i.e. Advancing the Grid) is a "longer-term proposition for Connecticut." This contradicts its stated goals on DER enablement and a dynamic modern grid and the priorities of utilities across the country.

Modernizing the grid should not be a longer-term proposition, but should be strategically designed now to ensure the Company can rapidly scale up the tools and programs that would defer traditional buildout and run its system as efficiently as possible. If PURA decides to approve a version of the TSP, the Company should not accept Eversource's artificial tiering but instead prioritize investments within the proposed TSP that enable it to rapidly scale up to a "flexibility first" approach that ensures future capital plans consider the full range of modern, cost-effective solutions. Specifically, Eversource should be using the upcoming term of the proposed TSP to rapidly gain operational experience with key DER flexibility approaches such that these programs can be scaled by the end of the TSP term and leading into the next cycle of investments.

As described in my testimony below, my recommendations outline a streamlined and strategic alternative proposal to support these objectives that a) reduces investment levels across the Sustained and Targeted System Performance tiers while b) bringing forward key Advancing the Grid Investments.

B. Sustained Tier

Q19 How does the Company define and justify the Sustained tier?

A. The Sustained tier totals $3.611 billion from 2027 through 2031.[21] The Company describes it as necessary to maintain reliability "at levels that the Company has generally maintained since the last rate case in Docket No. 17-10-46 (2018)," and as "the minimum level of investment needed" to do so.[22] The Company projects that the tier would improve five-year SAIDI by 0.7 minutes, which it describes as maintains current performance.[23]

The Sustained tier, however, is not simply a continuation of current spending. It includes several significant increases. The Company proposes to increase substation transformer replacements from an average of three per year in the 2026 budget to six per year, compared with a historical pace of one to two per year.[24] It also increases Grid Modernization spending from $10 million in 2026 to a $14 million per year, and vegetation management from $59 million to $91 million per year.[25] In addition, the tier includes $400 million for New Customer and $393 million for Peak Load/Capacity. [26]

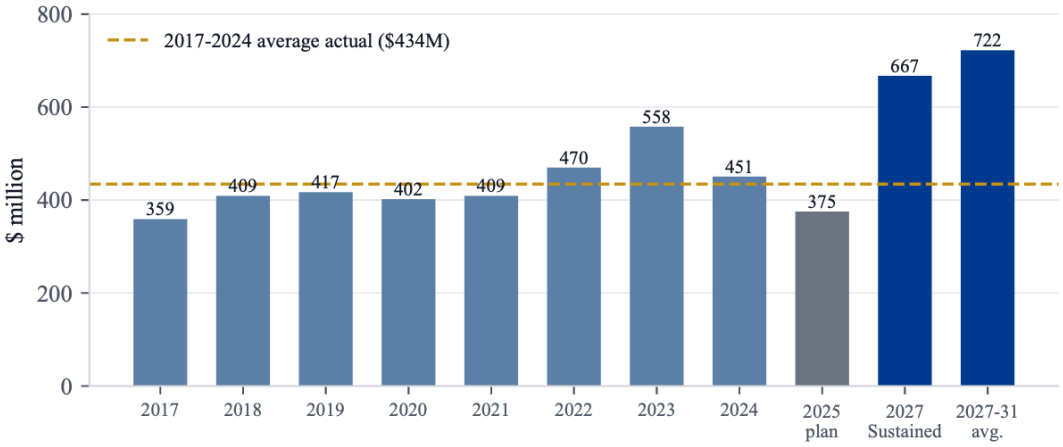
Because the Company describes this tier as the minimum needed, it should show why each of these increases is necessary to achieve that result. The record does not yet demonstrate that connection.

[21] Exh. CLP-TSP-3 at 8.
[22] Exh. CLP-TSP-1 at 17.
[23] Exh. CLP-TSP-3 at 8, 11.
[24] Exh. CLP-TSP-3 at 11, Response to OCC-597.
[25] Exh. CLP-TSP-3 at 11.
[26] Response to OCC-811.

Q20 How does the Sustained tier compare with Company's capital spending since 2017?

A. The Sustained tier exceeds the Company's actual capital expenditures in every year from 2017 through 2024. The Company's annual Capital Books report those expenditures and provide the closest comparison in the record to the proposed five-year plan.[27] From 2017 through 2024, Connecticut Distribution capital expenditures averaged $434 million per year and peaked at $558 million in 2023.[28] By comparison, the Sustained tier would spend $667 million in 2027 and average about $722 million per year over five years.[29]

Figure 1: Connecticut Distribution Capital, Actual and Planned, Compared with the Sustained Tier ($ million)



The largest growth categories show a similar pattern on an in-service basis (Figure 1). Under the Sustained tier, annual New Customer investment would be nearly twice the historical average, Peak Load/Capacity would be about two and a half times higher, and substation transformer replacement would be nearly six times higher. The historical amounts are plant placed in service, while the tier amounts are planned investment, so the comparison is indicative rather than exact.

[27] Exh. CLP-ADDITIONS-12.
[28] Exh. CLP-ADDITIONS-12 at 28, 45, 65, 83, 102, 121, 145, 167.
[29] Exh. CLP-TSP-3 at 10.

Table 1: Sustained Tier Compared With 2017–2025 In-Service Additions[30]

Category	2017–2025 in service (avg. per year)	Sustained tier 2027–2031 (avg. per year)	Increase
Peak Load / Capacity	$31.0M	$78.6M	2.5×
New Customer	$42.6M	$80.0M	1.9×
Substation transformer replacement	$8.6M	$48.7M	5.7×

Q21 Is the Company's description of the Sustained tier as a minimum consistent with its 2025 capital plan?

A. No. The Company's own statements do not support treating the Sustained tier as a clear minimum.

First, the Company states that past investments have consistently proven to be "right sized" to maintain reliability and that the system "has continued to perform well for customers, so long as there is adequate and consistent investment made to maintain the system in its current state, which the Company has achieved." The Company now states that "the system is at a crossroads where a step-up in investment is needed."[31] If past spending was sufficient to maintain reliability, the Company should explain why a much higher level is now the minimum needed to do the same.

Second, the Company cut its 2025 Connecticut capital plan for reasons unrelated to system need to $375.3 million, from $450.6 million actual in 2024.[32] The 2025 capital book states that the Plan reflects a reduction in spending for Connecticut to lower the cost recovery risk, and identifies a "decrease in overall CT capital plan due to regulatory recovery risk" [33] as the first variance driver. When asked whether that level fell below what was needed to maintain reliability, the Company

[30] Response to OCC-811.
[31] Exh. CLP-TSP-1 at 22–23.
[32] *Id.* at 167.
[33] Exh. CLP-ADDITIONS-12 at 167.

responded that the 2025 investment amount was not below the level the Company considered necessary to maintain reliability in the short term.[34] It added that "there is no 'reliability or safety consequence' associated with such a short-term deviation in budget expenditures", and that it took "significant care to identify capital work that could be toggled back without an immediate impact to safety and reliability."[35] The Company's dedicated reliability investment was $123.4 million in the 2025 plan. Under the Sustained tier it would be $236.6 million in 2027.[36]

The Company also states that a sustained reduction in spending could affect reliability by 12 to 15 percent over five years, "assuming no improvement in the reduced expenditure level."[37] I do not dispute that consistent investment is necessary. The issue is that the Company has not shown where the actual minimum lies between the lower 2025 spending level and the Sustained tier's average of about $722 million per year.

Finally, the Company acknowledges that its reliability "remains in the top quartile based on the IEEE benchmarking study."[38] PURA has identified top-quartile performance in the four years before a rate case as a consideration in deciding whether to approve a plan designed to improve reliability further.[39] The Sustained tier, by the Company's own description, is designed to maintain performance, not improve it. Holding a top-quartile position should not require spending well above the levels that produced that position.

Q22 How does the Company calculate the reliability benefit of each tier?

A. The Company assigns SAIDI improvement to only two capital programs – Reliability Improvement Specific Projects and the Smart Switches Program, along

[34] Response to OCC-795.
[35] Response to OCC-781.
[36] Response to OCC-795.
[37] Response to OCC-781.
[38] Exh. CLP-TSP-3 at 32;
[39] Docket No. 17-12-03RE08, Decision at 44.

with vegetation management. It then applies a "System Degradation" factor that worsens SAIDI by the same 15.6 minutes under both tiers.[40]

I have several concerns with this approach. First, the degradation factor has a significant effect on the result, but the Company has not provided the basis for that assumption. Second, the Sustained tier produces a net SAIDI improvement of only 0.7 minutes, or about one percent of 2025 Blue-Sky SAIDI, even though the Company describes the tier as the minimum needed to maintain reliability.[41] Third, the additional SAIDI benefit of the TSP tier comes entirely from the same two reliability programs. The Company assigns no SAIDI benefit to the resilience or asset health portions of the second tier of proposed TSP investment, which accounts for about $298 million of the $374 million.[42]

Q23 Has the Company's past capital spending delivered the reliability results it now projects?

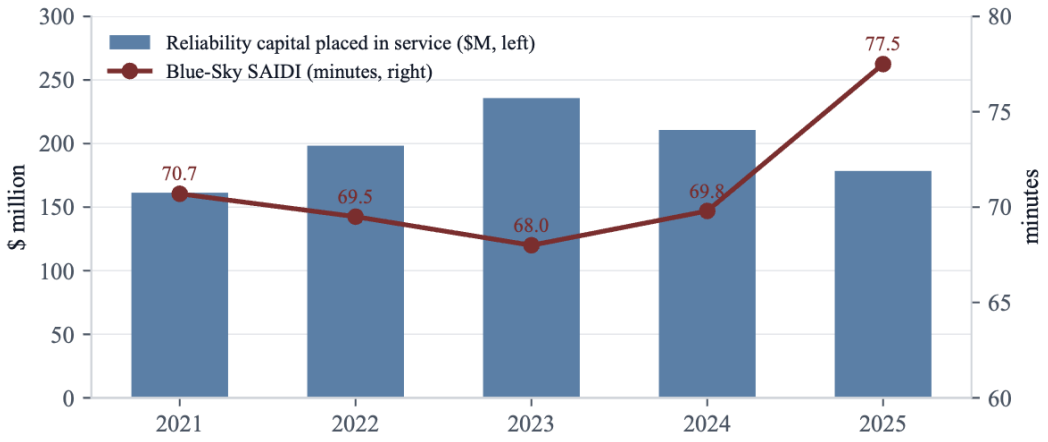
A. The Company's own data does not show that it has. From 2021 through 2025, the Company placed about $985 million of reliability capital in service.[43] Over the same period, Blue-Sky SAIDI increased from 70.7 minutes in 2021 to 77.5 minutes in 2025, after improving slightly through 2023.[44] I am not suggesting that reliability capital produced no benefit, or that a single year's result proves anything. Weather and other factors affect annual reliability results. But the Company asks PURA to accept a projected 6.1-minute improvement under the TSP tier, while also explaining that its past spending "cannot necessarily be directly and instantaneous[ly] translated to SAIDI and SAIFI performance." When asked to identify the expected reliability performance associated with the 2021–2025 spending when it was authorized, the Company did not identify one.[45]

[40] Response to OCC-807.
[41] Exh. CLP-TSP-1 at 17, 76; Response to OCC-807.
[42] Response to OCC-809.
[43] Response to OCC-804 Attachment 1.
[44] Exh. CLP-TSP-1 at 76, Table 1.
[45] Response to OCC-804.

The selection process behind that spending also matters. The Company's cost-effectiveness ranking tool, ReBOT, was first used "to drive reliability work in 2024 to support the selection of the 2025 TripSaver program."[46] None of the 2017–2024 reliability capital was selected using that tool. In 2023, when actual spending exceeded plan by $91.5 million, the Company identified the two largest additions to the capital plan as an approximately $22.0 million trip-saver program and approximately $20.0 million of circuit patrol fixes addressing deficiencies identified by a third party.[47]

The 2017–2025 record is therefore important context for evaluating the Company's new five-year projections. That record does not, by itself, support pre-approving five more years of substantially higher spending on the strength of projected reliability benefits. I address the prudence of the 2017–2025 additions separately in the Capital Additions section of my testimony.

Figure 2: Reliability Capital Placed in Service and Blue-Sky SAIDI, 2021–2025



[46] Response to OCC-792.
[47] Responses to OCC-780 and OCC-792.

The Sustained Tier's Growth Drivers

Q24 What spending is at issue?

A. The Company's direct testimony states that average baseline funding for Peak Load/Capacity is approximately $50 million per year for substations and $19 million per year for lines, or about $345 million over five years.[48] The Company's capital-plan presentation, however, shows $393 million of Capacity spending over the same five-year period under the Targeted System Performance tier.[49] In discovery, the Company also reports $393 million for both the Sustained and Targeted System Performance tiers.

The capital-plan presentation and discovery responses are consistent with each other, but they leave an approximately $48 million difference from the amount described in direct testimony. The Company should explain whether that difference reflects updated estimates, different project scope, or another adjustment, and identify the amount actually included in its request. It should also reconcile that amount to the underlying substation and line projects, annual spending, and any program-level allowances. Without that reconciliation, it is difficult to determine what work the proposed funding would support.

Q25 Was the Company required to evaluate non-wires solutions before seeking funding for its capacity projects?

A. Yes. The Company's own planning documents and PURA's NWS process both call for alternatives to be identified and compared before a wires solution is funded.[50] The Company's 2021 NWA Framework screens station capacity needs first, using standard technical and cost assumptions, so that only viable candidates proceed to detailed engineering; its economic test compares the present value of

[48] Exhibit CLP-TSP-1 at 50
[49] Exhitbit CLP-TSP-3 at 42
[50] I use "non-wires solutions" ("NWS") in this section and retain "NWA" when referring to the Company's 2021 NWA Framework.

the non-wires alternative plus the deferred conventional project with the conventional project built when first needed.[51] The Framework also disqualifies any need that arises within two years of the base year, and any station with a transformer health index above 0.5.[52] The Company states that it now follows the process PURA approved in Docket No. 24-08-08,[53] but it has not stated whether it still applies the Framework's two-year exclusion.

The Company's Distribution System Planning Guide ("DSPG") follows the same approach. It states that "the most cost-effective solution should be proposed as the preferred solution," with additional alternatives included in the initial funding request ("IFR") and Solution Design Committee ("SDC") process, using a ten-year view of capital, maintenance, energy and replacement costs.[54] The Guide also directs that NWS screening to consider these same cost elements over the standard ten-year planning horizon.[55]

PURA's NWS process is consistent with this principle. PURA has stated that "all planned capital investments with an estimated cost greater than $250,000 should be accounted for in either the Grid Needs Filing or in the quarterly filings."[56] It "will consider the EDC's compliance or non-compliance with the NWS process as evidence in determining whether the Company acted in a prudent manner."[57] PURA has also confirmed that the Company keeps its burden of proof under the prudence standard when it seeks cost recovery.[58] In April 2026, PURA closed the second NWS cycle without a screening decision and paused further cycles to

[51] Response to OCC-578, Attachment 1 at 9–12.
[52] *Id.* at 9.
[53] Response to OCC-578.
[54] Response to CLF-SC-023, Attachment 1, at 41.
[55] *Id.* at 40.
[56] Docket No. 25-08-08, Decision (Dec. 10, 2025) at 12.
[57] Docket No. 24-08-08, Decision at 9 n.4.
[58] Docket No. 25-08-08, Decision at 1 n.1.

redesign the process. It directed, however, that its NWS orders "remain in effect" and that the Company continue its Grid Needs and quarterly filings.[59]

My concern is that the record doesn't establish that the Company evaluated reasonable alternatives before seeking funding for capital investments included in the TSP. I am not suggesting that a non-wires solution will fit every need or that every project requires a competitive solicitation. However, Eversource needs to demonstrate that adequate consideration was given to cost-effective solutions.

Q26 Has the Company demonstrated that it followed that process for the substation projects in this plan?

A. No. The Company states that its substation capacity projects "are all at the conceptual stage," "do not currently have planned in-service dates," "do not have approved scopes of work," and "do not currently have NWA solutions identified." Several measures needed to evaluate alternatives – energy above rating, the duration or event frequency remain undeveloped. The Company also states that it "does not currently generate an hourly load forecast."[60] The Company states that it creates 24-hour load profiles for a station once a need is identified, but it did not provide any for these projects.[61]

The Company's own sequence runs backward. It states that "following initial funding of these projects, all available solutions including permanent load transfers, non-wires solutions, and traditional solutions are identified and evaluated." Several projects have already passed that point. Triangle 11A, Rockville 14W, Tracy 14M and Frybrook 13B have initial funding approved, Baldwin 13F has initial funding submitted, and Campville 14R has partial funding.[62] The Company should reconcile that description with the DSPG's

[59] Notice of Docket Closing, Docket No. 26-08-08 (Apr. 17, 2026) at 1.
[60] OCC-594 at 1–3; OCC-812 at 1.
[61] Responses to OCC-574(b) (f), and OCC-587(b)
[62] Response to OCC-599.

expectation that alternatives inform the IFR and provide the screening records associated with each project's actual approval stage.[63]

The Company's own record also indicates that these needs are not urgent. It states that "[a]ll substation forecasted violations are mitigated by using pre-contingent load transfers to adjacent substations with remaining capacity." For two listed substations, Rocky Hill 12Y and Brooklyn 30Y, it anticipates a permanent load transfer "with settings changes only." It describes permanent load transfers as "in many cases, a preferred solution" that is "typically substantially lower cost than substation investments," yet it did not track those transfers before 2024.[64]

Because PURA treats NWS compliance as evidence of prudence, the burden is on the Company to show that screening informed the funding it seeks. A commitment to screen these projects after rates are set does not meet that burden.

Q27 Does the record for the Company's own non-wires candidates support the amounts it requests?

A. No. The Company presents battery proposals for Campville 14R and Frybrook 13B. For Campville, it identifies a 6.5 MW/11 MWh system estimated at $24.06 million against a $77 million traditional solution. For Frybrook, it identifies a 2.5 MW/10 MWh system estimated at $20.1 million against $25 million.[65] In discovery, the Company states that both proposals remain conceptual, have initial funding approved, and must be reevaluated against other solutions before a final proposal is selected, and that the underlying needs are funded in the Sustained tier.[66] Its cost tables now carry $52.3 million for Campville and $20 million for Frybrook without reconciling those figures to either the battery or the traditional

63 OCC-599 at 2–3; CLF-SC-023, Attachment 1 at 41.
64 Response to OCC-599 at 2–3.
65 Exh. CLP-TSP-3 at 103, 105–106. The Company notes that these figures were filed in Docket No. 22-06-05 and would change if updated.
66 Response to OCC-579(a)(i)–(ii).

alternative.[67] My concern is not that no NWA work exists, but that the Company has not shown which current scopes, costs and alternatives support the amounts it asks customers to fund.

PURA's review of West Brookfield 14H does not close that gap. PURA reviewed the Company's battery comparison for the $16.9 million transformer project, identified a potential NWS opportunity, and accepted the Company's decision not to issue a solicitation, stating that the decision would not be construed as noncompliance.[68] I do not suggest otherwise. PURA did, however, find that "comparing the cost to a BESS with an assumed $2 million per MWh cost is an inadequate methodology to screen grid needs," and that the Company did not explain how alternatives other than batteries were considered, while recognizing a good-faith screening effort. The relevant question is whether the analysis supporting the investments in this case addresses those deficiencies. As I explain below, it does not: the Company's January 2026 Grid Needs narratives still price battery alternatives at "$2M per MWh."[69] West Brookfield also demonstrates why screening and funding status must be reported by project rather than described through a single characterization of all substations.

Q28 Are the line capacity and New Customer budgets supported by identified, screened projects?

A. Only in part. The Company budgets about $19 million a year for line capacity, or roughly $95 million over five years.[70] Its list of feeder capacity projects contains 21 projects totaling $19.46 million, with in-service dates in 2027 and 2028. Because that list reports project costs rather than a five-year spending schedule,

[67] Response to OCC-599(a) at 2.
[68] Response to OCC-590, Attachment 1; Decision, Docket No. 25-08-08 at 1, 7–8.
[69] Response to OCC-590, Attachment 3 at 5.
[70] Exh. CLP-TSP-1 at 49–50.

the difference does not by itself establish excess funding. It does show that the Company has not identified what most of the allowance would fund.[71]

The screening record is also incomplete. Several of the identified projects do not appear in the 2025 or 2026 Grid Needs Filings.[72] While some may fall below the filing thresholds, the record does not clearly show how the full set of projects was screened through the NWS process. An absent listing does not by itself establish noncompliance, but the Company should identify the screening result or documented basis for exclusion for each project.

The New Customer budget of $400 million averages $80 million a year.[73] Actual New Customer spending was $41.0 million in 2022, $60.2 million in 2023 and $63.2 million in 2024.[74] The Company's 2027 project list includes a $50.0 million line item for "Requests for New Service work less than $250k," with no location or scope identified ("TBD").[75] I recognize that New Customer work is driven by customer requests and is not subject to NWS screening. The Company should nonetheless support a near doubling of the historical run rate with a forecast of requests, not an unspecified allowance.

Q29 What does the Campville right-of-way rebuild show about the Company's evaluation of alternatives?

A. It shows that the Company continues to rely on the screening method PURA found inadequate.

The comparison prices a 22.5 MWh battery at "$2M per MWh," the assumption PURA found inadequate, and compares costs without the ten-year total-cost view

[71] Response to OCC-594, Attachment 1.
[72] Response to OCC-590, Attachments 1–2; Response to OCC-594, Attachment 1.
[73] Exh. CLP-TSP-1 at 49.
[74] Exh. CLP-TSP-3 at 53.
[75] Response to OCC-813, Attachment 1.

the Company's own Planning Guide requires.[76] At the approximately $420,000 to $450,000 per MWh that PURA cited for UI, the same battery would cost about $9.5 million to $10.1 million.[77] That does not establish that a battery is the better choice; the rebuild also replaces aging conductor, and the battery would support the contingency for four hours. It does establish that the Company's screening cannot support its funding requests. The Company should separate capacity relief from unavoidable asset-condition work and compare technically feasible options on a consistent, lifecycle basis.

Q30 Are you recommending that all capacity work be stopped?

A. No. N-1 overloads can create legitimate investment needs even when equipment operates within its ratings with all elements in service. My recommendation concerns approval of the proposed budget on this record. The Company should complete the substation due diligence before the substation capacity allowance is approved; the line-project budget may be approved once the reconciliation and NWA process requirements described above are satisfied.[78]

Q31 Is the Company's transformer replacement volume based on the condition of its fleet?

A. No. The proposed replacement volume appears to be driven in by an age-based goal. The Company's "Asset Health philosophy for transformers" is to "maintain a transformer fleet that does not exceed 70 years of age and an average age of approximately 35 years." At the same time, the Company confirms that no law, regulation, manufacturer requirement, or mandatory engineering standard requires retirement at any specific age.[79] The units included in the plan are described as

[76] Response to OCC-590, Attachment 3 at 5;.
[77] Decision, Docket No. 25-08-08 at 7, 10.
[78] OCC-594(e) at 2; OCC-599(c) at 3; OCC-812(b) at 1–2.
[79] Response to OCC-596.

"proactive replacements of units over 50 years old with asset health concerns." Only one project, Stevenson 14A, replaces a transformer that has already failed.[80]

The Company also has condition-based information available to support replacement decisions. It evaluates transformers using EPRI's Power Transformer Expert System ("PTX"). The company reports 27 units, or about 8.6 percent of its Connecticut fleet, in poor condition.[81] Its engineers recommend replacement when two of six parameters are high risk, and age being only one of those parameters.[82] For other distribution assets, the Company states that it uses a "condition-based asset management approach"[83] and "does not replace equipment solely based on age or failure risk without first conducting an appropriate assessment."[84] The transformer replacement plan does not appear fully consistent with that stated approach.

Q32 Does the Company's failure record and failure model support the proposed replacement volume?

A. No. The Company's six most recent transformer failures were all internal failures, at ages 32, 50, 52, 52, 56 and 83.[85] Five of the six occurred before the Company's 70-year age goal. The oldest unit on the system, Shepaug 13A-21X, is 85 years old and has short-term and long-term health index values of 0.194 and 0.289, both well within the healthy range. The Company nonetheless confirms that the unit is in the replacement plan, and states that its exhibit indicating otherwise "was an error."[86]

[80] Response to OCC-595.
[81] Response to OCC-596.
[82] Response to OCC-597.
[83] Response to OCC-800.
[84] Response to OCC-801.
[85] Response to OCC-596.
[86] Response to OCC-598.

The proposed replacement volume is also several times the historical pace and exceeds the number of units the Company rates in poor condition (Table 2).

Table 2: Substation Transformer Replacement Comparison

Basis	Replacements per year	Five-year total
Historical pace	1 to 2	5 to 10
2026 budget	3	15
Sustained tier	6	30
TSP tier	6 in 2027–2029; 8 in 2030–2031	34
Units now in poor condition (PTX above 0.5)	–	27

The Sustained tier alone would replace more units than the Company rates in poor condition. A condition-based approach would start with those units and evaluate, as the Company's own process contemplates, whether repair, refurbishment, load transfer, or use of spares can address the risk before replacement is required. The resulting replacement count could therefore be lower than 27.

The additional replacements also do not change the number of failures the Company expects. Its plan summary shows one transformer failure per year beginning in 2030 under both the Sustained and TSP tiers.[87] When asked what the two additional annual replacements under the TSP tier would change, the Company stated that the reduced risk would allow failure funding "to be diverted into other areas of need within the asset health portfolio." It did not quantify the reduction in risk or identify any corresponding savings to customers.[88] The Company also has not provided any deferral or life-extension analysis for the units proposed for replacement, stating that "project sequencing and deferral options will be evaluated" after initial funding.[89]

The Company's own maintenance practices also support a condition-based approach. It states that it "has effectively maximized the life of Transformers by extensive maintenance and monitoring practices," and that spares "are an

[87] Exh. CLP-TSP-3 at 11.
[88] Response to OCC-810.
[89] Response to OCC-597.

effective mitigation plan for emergent failures," although not a "one-size fits all" long-term solution.[90] I agree that spares alone are not a long-term strategy. But continuous monitoring and PTX trending may provide information on declining condition and can support replacement when a unit's condition warrants it, within the two- to five-year lead time the Company describes.

Q33 Has the Company supported the cost of its transformer replacement program?

A. Not fully. The Company describes the program in several different ways and has not provided a clear cost per transformer. Table 3 shows the average per-unit cost implied by the Company's own statements.

Table 3: Average Cost per Transformer Implied by Company Statements

Company statement	Implied average per unit	Source
About $78 million a year for an average of eight transformers	~$9.8M	CLP-TSP-1 at 56
Sustained tier: $243.3 million for 30 units	~$8.1M	OCC-811
TSP tier: $273.3 million for 34 units	~$8.0M	OCC-811
Increment: $15 million a year for two added units in 2030–2031	$7.5M	OCC-810
2017–2025 in service: $77.0 million at one to two units a year (9 to 18 units)	~$4.3M–$8.6M	OCC-811

Planned spending also increases faster than the planned replacement volume. Average annual spending under the Sustained tier is about 5.7 times the historical in-service level, while the number of units replaced per year increases by roughly three to six times. This suggests a higher average cost per transformer, but the Company has not explained that increase.

The Company states that unit cost metrics are "not a reliable means of tracking" its annual projects.[91] But transformer replacements are discrete projects with

[90] *Id.*
[91] Response to OCC-789.

individual authorizations. The Company should therefore provide the expected cost and scope for each transformer it proposes to replace.

Q34 What do you recommend PURA do with the Sustained tier?

A. PURA should neither accept the Sustained tier as the minimum investment level nor approve it as a five-year budget. The Company has not demonstrated that its proposed spending above historical levels is cost-effective or affordable, nor has it adequately demonstrated the need for the proposed capacity investments and transformer replacement volumes.

If PURA authorizes any forecast capital spending under the Sustained tier, it should:

- Historical Baseline: Require the Company to establish the historical spending baseline prescribed by the Reliability Framework, escalated as directed by PURA, and justify any spending above that baseline through documented project- or program-level need and quantified benefits.

- Substation Capacity: Exclude from forecast-based recovery projects lacking an approved scope, cost estimate, in-service date, or documented NWS screening. Such costs should be considered only after the required information is provided.

- Line capacity: Require documented NWS screening results or justified exclusions for each project, using updated battery cost assumptions rather than the $2 million/MWh assumption previously rejected by PURA.

- Transformer replacements: Limit replacements to transformers with documented poor condition, along with the failed Stevenson 14A unit, supported by unit-level condition assessments, evaluated alternatives, and cost estimates.

- New Customer investments: Require the Company to substantiate the proposed budget with a documented forecast of customer service requests.

These recommendations are consistent with OCC Witnesses Wilson's and Tully's recommendation that PURA reject the TSP and use the IDSP process to inform any future multi-year capital investment plan.

C. The Targeted System Performance Tier

Q35 What does the $374 million TSP increment fund, and when would it be spent?

A. The increment has three components: $155.0 million for resilience, $143.3 million for asset health, and $75.8 million for enhanced reliability. Most of the spending occurs late in the five-year period. Of the $374 million total, $228.1 million, or about 61 percent, would be spent in 2030 and 2031.[92]

Under the F-Factor, PURA would approve the full amount now for work that would largely begin years later. Second, apart from the $155 million spacer cable resiliency plan, the increment mostly accelerates programs the Company already runs: smart switches, right-of-way lines, underground and overhead conductor replacement, programs for worst-served customers and towns, and, in 2030 and 2031, substation aging infrastructure and two more transformer replacements a year. The items the Company names account for about $119 million of the $143.3 million asset health amount. The Company has not identified the rest.[93]

Q36 Does the TSP increment meet PURA's requirement to quantify incremental benefits?

A. No. The increment is the clearest test of that requirement, and the Company's own answer shows that it has not met it. The Company describes the Sustained

[92] Response to OCC-809.
[93] Response to OCC-809.

tier as the minimum needed to maintain reliability.[94] By that definition, every dollar of the increment is discretionary. That is exactly the spending to which PURA's requirement applies: a budget above the historic baseline must quantify its incremental benefits, costs and reliability improvements.[95]

The Company was asked to explain what each TSP program adds beyond the Sustained tier. Its response points to a summary chart where the distinction is shown only through changed symbols.[96] Those symbols do not quantify incremental benefits.

The Company's own figures provide more detail, but they still do not support the $374 million increment:

- Enhanced reliability ($75.8 million). This is the only portion with a quantified reliability benefit. The Company projects about 5.4 additional minutes of SAIDI improvement over the Sustained tier, all from two reliability programs.[97] Measured against the full increment, that is roughly $70 million per minute, with no comparison to the value of that benefit.

- Resilience ($155.0 million). The Company states that it selected zones with "the highest potential for cost-effective resiliency improvement,"[98] but provides no cost-effectiveness result for any zone. The only quantified benefit is a value-of-lost-load estimate, not avoided storm restoration cost, as discussed below.

- Asset health ($143.3 million). The stated benefit is fewer emergent failures.[99] Yet, as discussed above, the Company projects the same

[94] Exh. CLP-TSP-1 at 17.
[95] Docket No. 17-12-03RE08, Decision at 47.
[96] Response to OCC-809, Exh. CLP-TSP-3 at 11.
[97] Response to OCC-807.
[98] Response to OCC-808.
[99] Exh. CLP-TSP-3 at 8.

transformer failure rate under both tiers. Equipment failure also accounts for 19.7 percent of blue-sky outage events and 1.9 percent of major storm-day events. [100]

The Company has the tools to perform this analysis. It describes its planning approach as "metrics-based," using benefit-cost analysis and measures such as "$/CMI saved" to prioritize reliability investments.[101] It also calculated a benefit-cost ratio for a $1.5 million-per-year storm analytics platform.[102] No comparable analysis was provided for the $374 million TSP increment.

The burden is on the Company to support the proposed spending. PURA should not approve $374 million based on qualitative indicators alone. If this analysis is provided for the first time in rebuttal, parties will have limited opportunity to test it, which PURA should consider in weighing that evidence.

Q37 Has the Company demonstrated that the resiliency plan will reduce storm impacts and storm costs for customers?

A. No. The Company states that the main goal of the TSP tier is "system hardening and reduced storm cost."[103] The record does not show either result. I have two concerns.

First, the Company's benefit analysis focuses on the value of lost load (Table T-8), which represents the economic costs customers experience during an outage. Storm restoration costs, by contrast, are costs recovered from customers through rates. PURA's resilience framework recognizes these as separate benefits and states that avoided storm restoration costs can be estimated based on shorter outages and "the cost of restoration crews that would have been needed if those

[100] Exh. CLP-TSP-2 at 12.
[101] Exh. CLP-TSP-3 at 34.
[102] *Id.* at 129.
103 Exh. CLP-TSP-3 at 12.

interruptions had occurred."104 A separate assessment of avoided restoration costs would help establish the extent to which the proposed investments could reduce storm-related costs ultimately borne by ratepayers.

Second, PURA's resilience framework calls for a benefit-cost analysis over several time windows, including avoided customer interruption costs, storm restoration costs, and vegetation and pole costs, using recent storm history to estimate storm frequency.105 One of the Company's witnesses led the work to build the benefit-cost analysis "required by PURA as part of its Reliability and Resiliency Framework."106 While the Company reports a benefit-cost ratio for its storm analytics platform. It does not present a comparable ratio for the broader resiliency plan. Without a consolidated assessment of costs and benefits, it is difficult to evaluate the cost-effectiveness of the proposed investments.

Q38 Has the Company supported the $71.0 million of O&M it proposes for the TSP tier?

A. The Fund would compensate customers for local grid services, including "deferral of infrastructure investments."[107] The Company has not provided a detailed breakdown of the $38 million, other than stating that "most of the budget" would go to customer compensation.[108]The grid DERMS needed to support the Fund would not be fully functioning until "the beginning of 2029."[109] I support paying customers for grid services, but the Fund should be tied to specific capacity needs and the investments it is intended to defer. Otherwise, customers could end up paying for both the alternative and the underlying capital investment.

[104] Docket No. 17-12-03RE08, Decision at 64–65.
[105] Docket No. 17-12-03RE08, Decision at 65–66 and Table 21.
[106] Exh. CLP-TSP-1 at 13.
[107] Response to OCC-581 at 1.
[108] Id. at 2.
[109] Response to OCC-582 at 3.

The vegetation management increase, from $59 million to $91 million per year, applies under all three tiers.[110] The Company also proposes 21 new vegetation management employees "to bring work in house," while stating that its vegetation proposal "will be based on results of [a] competitive RFP, currently underway." [111] [112] Until the RFP results and the proposed in-house staffing are reconciled with the $91 million spending level, the basis for that amount remains unclear.

Q39 Would customers be protected if the promised spending or benefits are not delivered?

A. Not adequately. As I explained above, the F-Factor reconciles only total plant in service. The Company's proposed reliability penalty would begin only when Blue-Sky SAIDI exceeds its five-year average plus one standard deviation, or 74.8 minutes on 2021–2025 data.[113] The Company's 2025 Blue-Sky SAIDI of 77.5 minutes was already worse than that threshold.[114] The penalties exclude major event days, so they do not measure the storm performance the resiliency plan is meant to improve.[115] The maximum penalty is $3.5 million per metric.[116]

Under the TSP tier, customers would pay for a promised 6.1-minute improvement whether or not it is achieved, and penalties would apply only if performance deteriorated beyond today's level. That allocation of risk is the reverse of what a customer-funded, forward-looking plan should provide.

[110] Exh. CLP-TSP-3 at 11.
[111] Exh. CLP-TSP-3 at 43.
[112] Id. at 112.
[113] Exh. CLP-TSP-1 at 75.
[114] *Id.* at 76, Table 1.
[115] *Id.* at 74.
[116] *Id.* at 79.

D. Relationship to the 2017–2025 Capital Additions

Q40 How does your review of the Company's 2017–2025 capital additions bear on the TSP request?

A. The Company asks PURA to find that approximately $4.3 billion of capital additions placed in service from 2017 through 2025 was prudently incurred.[117] In the same case, it asks PURA to place five years of forecast capital into rates through the F-Factor.[118] The historical record is therefore relevant to how the Company plans, authorizes, controls, and measures capital spending. It also provides an important benchmark for the TSP request.

First, history sets the baseline. PURA's Reliability Framework requires a budget above the historical baseline to quantify the associated incremental benefits, costs, and reliability improvements.[119] As discussed above, the Sustained tier alone, excluding Information Technology and Facilities, would average about 1.6 times the Company's 2017–2024 Connecticut Distribution capital spending. The 2017–2025 record is therefore the appropriate starting point for evaluating the TSP.

Second, the Company's approved plans have not consistently limited actual spending. Connecticut Distribution capital spending exceeded the annual Capital Book plan in seven of the eight years from 2017 through 2024, by a cumulative $350.7 million, or 11 percent. The largest variances were $84.0 million in 2018 and $91.5 million in 2023, about 26 and 20 percent above plan.[120] Spending was below plan only in 2024. When asked for documentation authorizing spending above plan, the Company referred to its capital books and total-company variance analyses but did not identify a separate authorization.[121]

[117] Exh. CLP-ADDITIONS-1 at 9, 45.
[118] *Id.* at 54.
[119] Docket No. 17-12-03RE08, Decision at 47.
[120] Exh. CLP-ADDITIONS-12 at 8, 28, 45, 65, 83, 102, 121, 145, 167.
[121] Response to OCC-779.

The supporting documentation was also limited. Before 2024, annual programs "were documented and supported by the Company's capital book," which the Company states "serves as documentation and approval of the capital plan."[122] In discovery, however, the Company described those books as giving departmental leaders an overview of the annual budget ultimately proposed to the Board of Trustees.[123] Annual programs and annual work orders account for approximately $2.29 billion of the additions; the Company did not dispute that amount when asked for the related authorizations.[124] The Company also acknowledges that some authorizations were prepared after the in-service date after an automated tool identified pending items.[125] Its testimony states that program-level authorizations require "a financial evaluation on a unit cost basis."[126] In discovery, it states that unit cost metrics "are not a reliable means of tracking" its annual programs.[127] At the same time, the Company justifies authorizing these programs in the aggregate because their costs are "highly consistent with the same cost drivers occurring over and over."[128] Costs that are highly consistent can be tracked per unit. A five-year capital plan approved in advance would rest on the same authorization practices.

Third, the TSP continues or accelerates many existing programs, sometimes under different labels. As discussed above, the increment includes programs customers have funded for years without clearly measured outcomes. The Company also states that work deferred from the 2025 plan "is planned for completion either as part of the 2026 capital plan, or as part of the Company's work plan over the next few years," without identifying whether that work is included in the TSP.[129]

[122] Exh. CLP-ADDITIONS-1 at 26.
[123] Response to OCC-779.
[124] Response to OCC-790.
[125] Exh. CLP-ADDITIONS-1 at 22.
[126] *Id.* at 37 n.4.
[127] Response to OCC-789.
[128] Exh. CLP-ADDITIONS-1 at 26.
[129] Response to OCC-781.

PURA should understand how prior work, deferred work, and proposed TSP spending fit together before approving forward funding.

Fourth, outcomes and overlap have not always been clearly measured. As discussed above, the Company could not identify the reliability performance expected when it authorized its 2021–2025 reliability capital, has not quantified the benefits of certain resiliency programs, and has not shown whether proposed TSP resiliency work overlaps with plant placed in service since 2017.

My conclusions on whether the 2017–2025 additions were prudently incurred are set out in the Capital Additions section of my testimony. For purposes of the TSP, the point is narrower: if the documentation supporting in-service plant is limited, PURA should not approve forward spending for projects that are still conceptual, lack completed alternatives analyses, or do not yet have quantified benefits.

E. Advancing the Grid Tier

Q41 What proposed investments do you address that were included in the "Advancing the Grid" Tier?

A. My testimony addresses the following investments:

- Distributed Energy Resource Management System ($24.1 million)[130]
- Grid Compensation Fund ($38 million)
- Planning Analytics – Advanced Forecasting and Planning Tools ($15 million)

[130] DERMS investment were included in both the "Sustained" and "Advancing the Grid" tier. Both set of investments are addressed here.

- Shared Hosting for Advancement of Renewable Energy (SHARE) Program

Q42 Are there other proposed investments in this rate case related to grid modernization?

A. Yes, the Company is proposing a rollout of AMI. While AMI is proposed as a separate investment from the "Advancing the Grid" tier, it is a core grid modernization investment that should be deployed in coordination with related investments including DERMS as well as advanced forecasting and planning tools. While I address the AMI investment in Section V, I address my recommendations on how this coordination should occur below.

Q43 How should the Company approach the sequencing and prioritization of grid modernization investments under this tier?

A. The Company's approach should include a coordinated set of investments grounded in key goals and associated use cases to realize such goals. Grid modernization should serve the purpose of enabling a flexible, optimized, cost-effective grid that maximizes the utilization of the system leading to the deferral and/or efficient buildout of infrastructure.[131] Fostering and scaling a robust market for cost-effective integration and utilization of DERs is central to achieving this vision. The Company acknowledges this by identifying DER enablement and a dynamic modern grid as two goals for its proposed TSP. However, the Company must provide additional detail on how these objectives will be achieved and how specific investments are directly tied to this approach.

[131] PURA Investigation into Distribution System Planning of the Electric Distribution Companies, Docket No. 17-12-03 (October 2, 2019), available at https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0e5fc32986954bf78525875200798b44/$FILE/171203-100219%20InterimDecision.pdf ("The Authority's Framework for an Equitable Modern Grid has four objectives: (1) support (or remove barriers to) the growth of Connecticut's green economy; (2) enable a cost-effective, economy-wide transition to a decarbonized future; (3) enhance customer access to a more resilient, reliable, and secure commodity; and (4) advance the ongoing energy affordability dialogue in the State, particularly in underserved communities.")

Q44 What key DER use cases will support these objectives and should be tied to the proposed grid modernization investments?

A. There are three key DER use cases that support these objectives and should inform the Company's investment strategy:

- **Dynamic Flexible Interconnection ("Flex IX"):** This is the process by which the utility use real-time data and control systems to dynamically manage DER output and which allows the Company to fully utilize available capacity and integrate more clean energy in constrained areas. This can drive affordability by using grid modernization technologies such as Distributed Energy Resource Management Systems (DERMS) to integrate greater amounts of DER capacity within the existing system and defer distribution system upgrades. These additional DERs can then be utilized for distribution and bulk power system grid services as described below. PURA's proposed final decision in Docket No. 25-01-27 recently set forth a pathway for dynamic flexible interconnection.
- **DER Grid Services (Distribution System):** This is the process by which the utility dispatches individual and/or aggregated DERs to address local distribution constraints (e.g specific substations and feeders). This can drive affordability by utilizing the flexibility of DERs to defer distribution system upgrades and ideally is done in a coordinated manner where DERs can provide services to the bulk power system as well to maximize their value across the system. PURA's proposed final decision in Docket No. 21-05-15RE02 acknowledges this as it includes a DER Services Metric tracks how DERs contribute to grid services across established programs.
- **DER Grid Services (Bulk Power System):** This is the process by which individual DERs and/or aggregated DERs are dispatched to address bulk power system constraints, provided they are coordinated with and do not conflict with distribution system constraints and obligations. This can drive affordability by utilizing the flexibility of DERs to defer transmission upgrades, mitigate spikes in capacity prices and ideally is

done in a coordinated manner where DERs can provide services to the distribution system as well to maximize their value across the system.

Q45 How must the distribution system evolve to support these use cases?

A. The distribution system must transition from a model based on static, conservative assumptions to one driven by dynamic hosting capacity and real-time optimization. Historically, utilities have managed grid access and infrastructure planning using "worst-case scenario" snapshots. This approach is inherently inefficient because it treats the grid's capacity as a fixed, immovable value, leading to unnecessary interconnection denials and premature infrastructure upgrades. Currently, utility planning often relies on a single or very few data points to estimate “peak load,” which then dictates multimillion-dollar capital investments. For example:

- **Fixed Export Limits:** For DER interconnection, utilities may use a single "minimum load" value to set export limits, assuming that high solar generation will always occur when local demand is at its lowest.
- **The "One-Hour" Peak:** Utilities often design an entire substation upgrade based on the estimated load of a single, extreme peak hour of the year. This results in an asset that may be significantly underutilized for the remaining 8,759 hours.

Moreover, it’s important to note that the distribution system has traditionally been modeled and planned at the substation level and that this evolution should apply to both feeders and substations.

Q46 What is dynamic hosting capacity and how does it improve grid performance?

A. Dynamic hosting capacity recognizes that the grid’s ability to accommodate resources is not static; it fluctuates constantly based on time of day, weather, and

localized demand.[132] The diagram below illustrates the concept of dynamic hosting capacity in the context of DER interconnection which shows that hosting capacity varies throughout the year and that DERs are only offered capacity based on the most conservative hosting capacity value in the year.

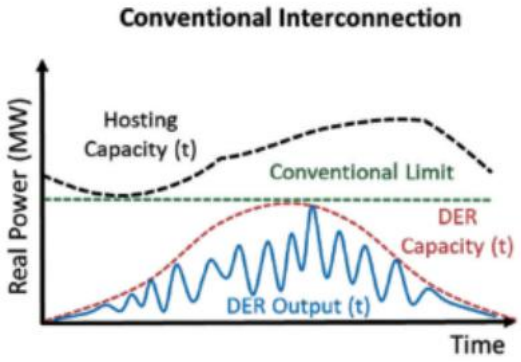


Figure 4: Dynamic Hosting Capacity[133]

By running the system according to real-time conditions rather than conservative static limits, we can unlock several DER strategies and associated benefits:

- **Increased DER Integration via Dynamic Flexible Interconnection:** Dynamic flexible interconnection allows more resources to connect to the grid immediately by curtailing their output in real-time during rare periods of actual congestion. Pepco acknowledges this their concept paper stating "current interconnection policies often use a DER's full nameplate capacity as a conservative assumption, treating every DER as if it is always exporting 100% of its power to the grid. This assumption is inaccurate and can lead to unnecessary system upgrades or the denial of new DER interconnections, even when there is available capacity".[134] The figure below illustrates how greater amounts of DERs can be interconnected when interconnecting these assets based on the dynamic

[132] National Renewable Energy Laboratory (NREL), Advanced Hosting Capacity Analysis. https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis
[133] Electric Power Research Institute (EPRI), Principles of Access for Flexible Interconnection Solutions, at 3 (Jul. 31, 2020), https://www.epri.com/research/products/000000003002018506.
[134] At 13-14

hosting capacity of the system and curtailing the DERs during the short periods when they exceed that hosting capacity.

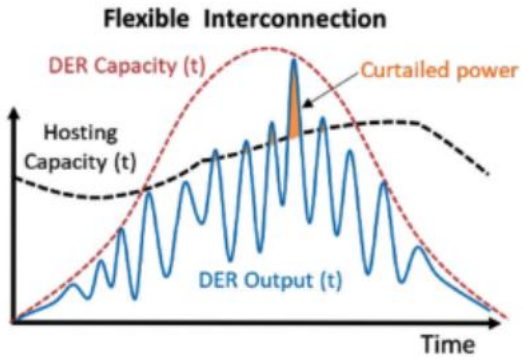


Figure 5: Dynamic Hosting Capacity – Dynamic Flexible Interconnection[135]

- **Targeted Locational Dispatch via DER Distribution Grid Services:** Utilities can dispatch individual or aggregated DERs in real-time to provide distribution grid services, addressing the actual peaks of the system exactly when and where they occur, thereby deferring or eliminating the need for traditional capital upgrades.

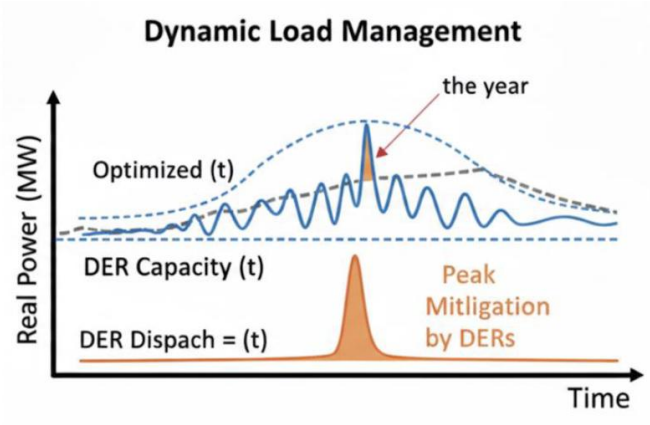


Figure 6: Dynamic Hosting Capacity – DER Distribution Grid Services

[135] Electric Power Research Institute (EPRI), Principles of Access for Flexible Interconnection Solutions, at 3 (Jul. 31, 2020), https://www.epri.com/research/products/000000003002018506.

Q47 What capabilities are needed to fully utilize dynamic hosting capacity and enable a flexible, cost-effective grid?

A. To move away from "fit-and-forget" infrastructure and toward a truly optimized grid, the utility must possess two core capabilities:

- **Real-Time Visibility:** The ability to see exactly how much capacity is available at any given node at any specific moment.

- **Granular Control:** The ability to communicate with and optimize DERs to curtail and/or dispatch them to align with system needs.

Without these capabilities, the utility is forced to remain conservative, resulting in higher costs and slower decarbonization. The Company's proposed investments should be focused on deploying and leveraging these capabilities to demonstrate and scale the three DER strategies described above. My recommendations below for each proposed investment reflect this approach.

DERMS

Q48 Please describe the Company's proposed DERMS investment.

A. The Company requests $24.7 million[136] as part of its "DERMS Demonstration" to demonstrate the value proposition of advanced DERMS capabilities, including (1) use of DER to increase system efficiency and reduce line losses; (2) integration of multiple types of DER in a microgrid application for critical load; and (3) investigation of lower cost approaches to communication and control of stand-alone solar and storage facilities integrated into the Company's centralized DERMS system.[137] This would serve as the first investment the Company is making in DERMS in Connecticut though it has made some enabling DERMS

[136] The Company proposed $10.7 million for its core DERMS deployment and $14 million for its DERMS demonstration.
[137] Exhibit CLP-TSP-1, at 68.

investments including Advanced Distribution Management System ("ADMS") power flow and aggregator DERMS.[138]

Q49 Please describe the use cases the Company intends to enable with DERMS and the current progress on deployment.

A. The Company expects the initial use cases to include flexible interconnection and local capacity relief at substations with the Grid Compensation Fund serving as an important enabler of the DERMS demonstration. The Company states the DERMS demonstration could incorporate the use of dynamic flexible interconnection and proves an example where the Grid Compensation Fund could provide incentives in exchange for a customer allowing use of an advanced inverter for a voltage management use case. Moreover, the Company is taking the following steps to deploy DERMS[139]:

- **ADMS-DERMS Integration:** The Company plans to integrate its ADMS and DERMS solutions from GE Vernova, which are designed to operate as an integrated solution. The ADMS-DERMS integration is currently in the planning stage.

- **DERMS DER Technical & Operational Requirements:** The Company is currently evaluating and developing the technical and operational requirements for the DERMS-DER gateway, including communication protocols

[138] OCC-582,(a), at 2.
[139] OCC-582, at 2-3.

- **Grid DERMS – Edge DERMS Architecture:** The Company is currently in the planning stage for designing the formal architecture governing the interaction between the grid DERMS and an aggregator/edge DERMS

- **Communications Architecture:** The Company is currently evaluating the communication architecture that will support direct communication with third-party DERs and aggregator/edge DERMS platforms

- **Deployment Timelines:** The Company estimates it would take approximately 18-months to implement a grid DERMS solution, including integration with third-party aggregator DERMS providers. Assuming a project start in mid-2027, the Company would have a fully functioning DERMS solution at the beginning of 2029

Q50 What is your position on the Company's proposal?

A. DERMS is a foundational solution to enabling a "flexibility first" approach to scale the integration & utilization of DERs to drive a more flexible, cost-effective grid. While I appreciate the Company's responses on its plan to deploy DERMS, the current plan represents an incremental approach with no clear line of sight into how flexibility first solutions (i.e dynamic flexible interconnection, DER distribution grid services and DER bulk power services) will be demonstrated and scaled by end of the proposed TSP term. Though DERMS is new in Connecticut, it is not new for Company[140] or for utilities across the country. Thus, any plan should take lessons learned from other jurisdictions and accelerate the path from demonstrations to scalability.

[140] The Company notes its experience with DERMS in Massachusetts.

Specifically, the Company's DERMS proposal has the following gaps:

- **Targeted deployment is too limited:** The Company states the DERMS demonstration program is designed to implement multiple DERMS-dependent use cases in a "targeted location"[141] and identifies the Triangle substation was identified as an opportunity for a DERMS demonstration.[142] However, simply focusing on one location could limit the ability to demonstrate and scale key DER use cases including the ones the Company mentions. The Company itself acknowledges DER potential is in rural areas in contrast to where load is concentrated[143] which means that focusing on one location will limit the ability to demonstrate both flexible interconnection and local distribution grid services. Moreover, the locations of aggregated DERs from the Company's connected solutions program may not overlap with load constraints but nevertheless it will be critical to demonstrate utility DERMS to an edge/aggregator DERMS dispatch to build the technical foundation to leverage VPPs to address distribution constraints.

[141] OCC-584, (b), at 3.
[142] OCC-585, (a), at 1.
[143] Exhibit CLP-TSP-3, at 29.

- **Minimal commitments on use case implementation:** The Company vaguely discusses that dynamic flexible interconnection *could* be implemented via the demonstration but provides no commitments or plans to do so. Moreover, the Company states the Grid Services Compensation Fund is an important enabler of the DERMS demonstration and provides examples of how the Grid Compensation fund could be tied to DERMS.[144] While I acknowledge the Company is in the planning stages, any approval of this investment should require a detailed plans on how and when use cases will be demonstrated and scaled. This should include details of the offerings, targeted locations and milestones for when demonstrations will occur.

- **No plan to scale:** The Company states that a fully functioning DERMS solution could be available at the beginning of 2029 but primarily discusses the demonstration program which will inform efforts to deploy at scale across Connecticut.[145] However, the Company offers no process or milestones for how and when DERMS will be scaled and for what use cases. When detailing the implementation of each use, the Company should also provide milestones on any subsequent evaluation period post demonstrations and when a scalable plan will be developed.

While I appreciate that DERMS is in its early planning stages and agree that it is appropriate to initially deploy DERMS at targeted locations, an iterative roadmap needs to be established for how, when and where DER use cases the Company intends to demonstrate each use case and how that will be scaled up. Such a roadmap is critical as DERMS is the connective tissue and unifying technology across a broad set of DER use cases and transitioning to a flexible, cost-effective grid. PURA acknowledges this in Docket No. 25-01-27 stating DERMS can "provide value across utility operations broadly" and "enable numerous present

[144] OCC-584, (b), at 3.
[145] OCC-584, (b), at 3.

and future utility functions in addition to flexible interconnection".[146] Both Illinois[147] and Massachusetts[148] have developed and/or required such roadmaps, which can be used to accelerate progress in Connecticut.

Q51 What should be included in this roadmap regarding flexible interconnection?

A. I recommend two key components be included in this roadmap: (1) commitments and timelines for estimated MWs enabled and (2) a broader voltage management strategy to support DER integration.

PURA's proposed decision on dynamic flexible interconnection requires a phased approach starting with 10% of substations by May 1, 2028 to 100% of substations by November 1, 2030, which aligns with my recommendation to scale up flexibility first approaches in the TSP term. As part of this roadmap, the Company should conduct a broader analysis of its substations to estimate how many MWs of additional DERs can be integrated and layout a timeline for doing so in the TSP term. Commonwealth Edison in Illinois recently committed to enabling 650+ MW of DERs over the next 5 years of their Multi-Year Integrated Grid Plan as described in the figure below.

[146] Docket No. 25-01-27, Proposed Decision, September 15, 2026, at 19.
[147] ComEd Grid Plan: DERMS and Flexible Interconnection Roadmap, January, 16, 2026. https://icc.illinois.gov/docket/P2026-0047/documents/375128/files/657435.pdf
[148] D.P.U. 23-115/D.P.U. 23-117/D.P.U. 23-126, Order, DPU directed the filing of a DERMS readiness plan, August 11, 2026, at 91.

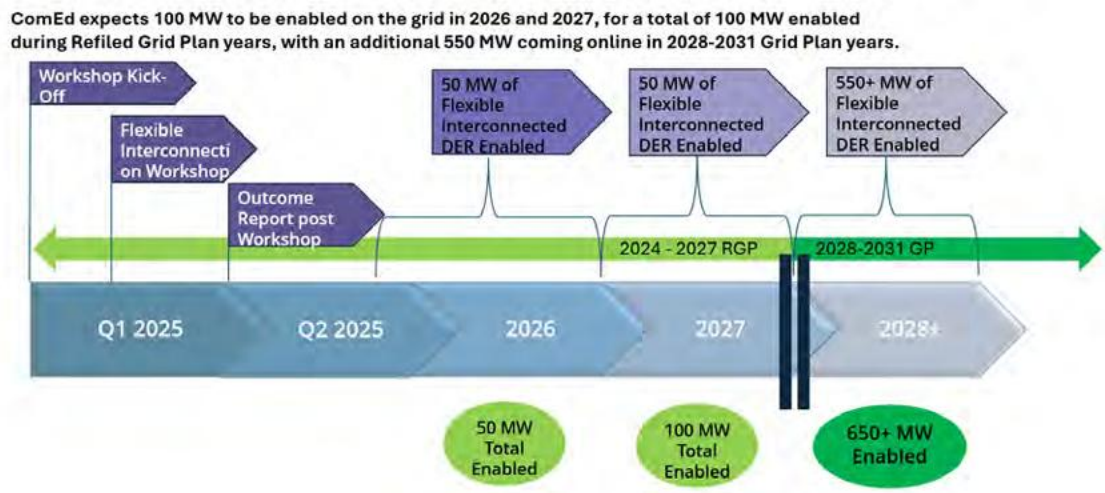


Figure 7: Commonwealth Edison DERMS and Flex IX Roadmap[149]

It is also important to recognize that this use case primarily relies on DERMS managing *thermal constraints* to accommodate more DERs. However, as more DERs are integrated beyond the static limits of the system, voltage issues are expected to rise which could limit the potential of dynamic flexible interconnection even if dynamic hosting capacity is available. ComEd recently proposed a Voltage Optimization Merger with plans to integrate Voltage Optimization ("VO") functionality into the DERMS platform to enable more precise voltage management control in areas with high-DER penetration. This would expand DERMS functionality to coordinate with voltage regulators and capacitors, enabling closed-loop voltage control for both firm and flexible DERs.[150] Thus, this roadmap should also include a broader strategy to integrate DERMS with the Company's broader voltage management strategy to mitigate the voltage impacts of DERs and thus maximize DER integration.

[149] ComEd Grid Plan: DERMS and Flexible Interconnection Roadmap, January, 16, 2026, at 12. https://icc.illinois.gov/docket/P2026-0047/documents/375128/files/657435.pdf
[150] ComEd Grid Plan: DERMS and Flexible Interconnection Roadmap, January, 16, 2026, at 16-17.

Q52 What should be included in this roadmap regarding DER distribution grid services?

A. I recommend three key components be included in this roadmap: (1) a direct link between DERMS and the programs implementing grid services such that DERMS deployment is informed by such programs; (2) targets for DERMS coverage at strategic locations that would benefit from various grid services; and (3) timelines for detailing and deploying an architecture that allows DERMS to dispatch aggregators and VPPs.

First, similar to flexible interconnection, DERMS deployment for grid services should be guided by the programs implementing grid services (i.e NWSs and the Grid Services Compensation Fund). As described below, the Grid Services Compensation Fund should identify and prioritize a comprehensive set of DER grid services the Company wishes to demonstrate. Accordingly, the Company should prioritize the demonstration of dispatch capabilities based on the services that will be provided. In eastern Massachusetts, the Company conducted its first locational demand response program in Summer 2026, utilizing its aggregator DERMS to reduce load during peak events at three substations in the Boston area with identified risk of overload. The Boston substation peak load reduction program was implemented in coordination with the Company's Massachusetts Grid. [151]

Second, similar to PURA's proposed order on flexible interconnection, I believe it is appropriate to have similar targets for DERMS coverage and availability for grid services across substations and feeders. However, it is important to recognize that different locations are more appropriate for different use cases. As part of developing these targets, the Company should identify and commit to timelines of DERMS coverage for specific locations that are expected to benefit from locational grid services such as load concentrated areas that need capacity and

[151] OCC-584. (a), at 1.

critical infrastructure that requires resiliency. This should be informed by the Company's NWA and Grid Compensation Fund priorities.

Finally, this roadmap should explicitly call out the Company's strategy for using its grid DERMS to dispatch aggregations of DERs (i.e the formal architecture governing the interaction between the grid DERMS and an aggregator/edge DERMS[152]) and should do so on a timeline in coordination with the Grid Compensation Fund.

Q53 What should be included in this roadmap regarding DER bulk power grid services?

A. This roadmap should detail how and when the Company intends to do Transmission & Distribution ("T&D") coordination for DERs provided grid services at different levels of the system. The Company currently dispatches DERs as part of ConnectedSolutions for ISO-New England system peak load reduction.[153] Moreover, ISO-NE's implementation of FERC Order 2222 for energy and ancillary services markets is set for November 1, 2026.[154] While I acknowledge that distribution grid services are in early stages and T&D conflicts are unlikely in the near-term, it is important to include this on the roadmap for eventual investigation once dynamic flexible interconnection and DER distribution grid services are scaled up.

Q54 What should be included in this roadmap on the broader locational deployment of DERMS?

A. As described above, DERMS serves multiple critical use cases often at entirely different locations on the system. Thus, the Company will likely need to balance competing priorities. The Company should detail more broadly how it intends to

[152] OCC-582, (c)(iv), at 3.
[153] OCC-584, (a), at 1.
[154] https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy

deploy DERMS across its system and how it will prioritize specific locations and use cases.

Q55 What should be included in this roadmap on the coordination of other grid modernization investments?

A. The Company should detail how the DERMS deployment will be coordinated and sequenced with other investments including Advanced forecasting capabilities and AMI. Specifically, advanced forecasting and AMI should ideally be deployed iteratively at specific locations aligned with where DERMS can enable specific flexibility approaches.

Q56 What is your recommendation?

A. If PURA approves a version of the TSP, I recommend the proposed DERMS investment be approved only conditional on the development of an iterative roadmap with annual updates that details following:

- How and when dynamic flexible interconnection, DER distribution grid services and DER bulk power services will be demonstrated and scaled as further described above.

- A broader strategy for how DERMS locational deployment will be prioritized across the company's service territory to balance the implementation of various use cases as further described above.

- Details on how various grid modernization investments will be coordinated with DERMS including advanced planning & forecasting tools and AMI

Grid Services Compensation Fund

Q57 Please describe scope of the proposed investment.

A. The Company is proposing $38m for the Grid Service Compensation Fund ("GSCF") to compensate customer-owned front of the meter and behind the meter dispatchable DER and flexible loads for providing local grid services dispatched by real-time system operators using the Company's grid and aggregator Distributed Energy Resource Management System. These offerings intend to leverage existing DER capacity to reduce distribution system infrastructure costs relative to traditional solutions. Specifically, DERs can provide valuable grid services for: 1) deferral of infrastructure investments when DER dispatch can reliably reduce peak demand on local infrastructure that is slated for upgrade due to load growth; 2) for bridge-to-wires opportunities when DERs can provide flexible capacity to mitigate local reliability risks for which traditional infrastructure solutions cannot be deployed in time to meet need; and 3) provide voltage support services in support of increasing electricity delivery efficiency.

The program would leverage the Grid Compensation Study developed for that program to inform compensation for grid services. The GSCF is intended to be implemented over a four-year period with learnings would supporting a regulatory process to develop a longer-term mechanism to compensate customers for providing local grid services. The Company would provide annual updates to PURA and stakeholders on implementation of the GSCF, including amounts spent on incentives and administration relative to the value created by the various use cases, including infrastructure deferral.[155]

Q58 Please describe your position on the proposed investment.

A. As previously stated, I believe demonstrating and scaling DER distribution grid services is foundational to transitioning to a flexibility first approach. The GSCF serves as a good starting point to build upon within the TSP to realize this vision. Specifically, there are several areas the Company's proposal does not address:

[155] OCC-581, (b), at 1-2.

- **Socialization & Iteration on Compensation Framework:** The Grid Compensation Study and the framework that governs compensation has not been implemented in Connecticut. Similar initiatives in other states, however, have shown the value of using this framework to accelerate demonstrations. If it moves forward with the TSP, PURA should establish appropriate milestones guiding the Company in its work with stakeholders to evolve this into a scalable framework that supports a market for DER distribution grid services.

- **Procurement Processes:** The process by which grid services are procured is a critical component to the long-term success of DER distribution grid services. There are several factors including lead time, procurement speed, data access etc. that all can play a role in whether grid services are successfully procured. The current proposal does not address this and should be scoped as part of the program.

- **Consolidation of Flexibility and DERMS Filings:** Given the Company commits to an annual filing, PURA may want to consider consolidating this filing with the DERMS roadmap described above. This annual filing could serve as a broader update on the Company's progress towards a flexibility-first approach that addresses DERMS, dynamic flexible interconnection and DER distribution grid services.

Q59 Please elaborate on the impact of the procurement process.

A. NWS approaches more broadly have achieved only limited success and have not led to the scale of distribution services or deferred infrastructure seen internationally. In contrast, the United Kingdom has scaled up distribution grid services through "flexibility markets" with significant success.[156]

[156] United Kingdom Power Networks avoided or deferred infrastructure at 91 million pounds in 2023/2024 with a total of 563 million pounds expected from 2023-2028.

While the Company's NWS framework is a constructive starting point, it remains fundamentally reactive and project-specific, which limits its ability to scale. Under the RIIO-ED2 regulatory framework[157], distribution system operators like UK Power Networks ("UKPN") are mandated to market-test 100% of all new high-voltage network requirements before investing in traditional reinforcement.[158] Flexibility is not an "alternative" in the UK; it is the default standard for procurement.

Q60 What are the core challenges with US based frameworks?

A. There are three primary systemic barriers that prevent non-wires alternatives from becoming a viable, scalable affordability lever:

- **Procurement Speed & Insufficient Lead Time:** Most U.S. frameworks, including the Company's, are reactive. Utilities identify a grid need and then screen for NWAs, often leaving only a narrow window for procurement. The lifecycle for an NWS solution can take three years, effectively disqualifying many near-term reliability needs. Moreover, the reliance on project-by-project RFPs can create significant administrative drag with a manual approach making it difficult to capture short-term grid needs or aggregate smaller resources.
- **Lack of Operational Trust and Verification:** There is a persistent trust gap regarding whether flexible assets—particularly residential VPPs—will show up when called. Without robust, automated monitoring and verification ("M&V") and standardized performance penalties, utilities default to traditional solutions even when DERs are more cost-effective.

[157] RIIO-ED2 is five-year electricity distribution price control (1 April 2023 – 31 March 2028), setting revenue allowances for 14 UK network operators. It focuses on enabling net zero, investing efficiently, and improving network resilience, with a strong emphasis on customer value, supporting innovation, and transitioning to smarter, flexible energy systems.

[158] UK Power Networks, Distribution System Operation (DSO) Strategy: RIIO-ED2 Business Plan Annex 5.1, (2021). https://library.ukpowernetworks.co.uk/library/en/RIIO/.

- **The "Pilot Mentality" and Lack of Regulatory Mandate:** Unlike the United Kingdom, where the regulator (Ofgem) mandated that flexibility be tested for every high-voltage requirement, U.S. utilities typically treat NWS as experimental add-ons. This creates a fragmented market where developers cannot justify the investment to participate because the pipeline of opportunities is uncertain and sporadic.

Q61 How can the insufficient lead time gap be addressed?

A. Leading Distribution System Operators in the United Kingdom, such as UKPN, have transitioned to a "Continuous Market" model[159] through two key mechanisms:

- **Long-Term Forecasting & Data Sharing:** UK DSOs publish a Distribution Network Options Assessment (DNOA) that provides a 60-month "look ahead" map of forecasted capacity needs. By sharing locational data through automated processes, this gives DER developers years of lead time to proactively market DER solutions to customers and ultimately site them before a formal tender is triggered.[160]

- **Standardized Framework Agreements:** Instead of bespoke RFPs for every project, UK providers "pre-qualify" once via a national Standard Flexibility Services Agreement. This lowers the barrier to entry, allowing even small-scale 10kW residential batteries to compete.[161]

[159] UK Power Networks, Distribution Network Options Assessment (DNOA) Methodology, (March 2025)
[160] Energy Networks Association (ENA), Open Networks Project: Launch Document, (2023). https://www.energynetworks.org/assets/images/Resource%20library/2023/Jan/ENA_23-LaunchDoc_v6.pdf
[161] Energy Networks Association (ENA), Standard Flexibility Services Agreement & Version 3.2 Updates, (April 2024). https://www.energynetworks.org/industry/flexibility-services.

Q62 How can the lack of operational trust and verification be addressed?

A. The Company can evaluate several mechanisms including the following:

- **Automated Monitoring and Verification:** DSOs in the United Kingdom use automated platforms to verify DER performance against a real-time meter baseline.

- **Commercial Penalties:** Standard UK agreements include financial penalties for non-delivery, incentivizing aggregators to maintain reserve capacity within their portfolios to guarantee a firm response.

- **Target high-loading but not fully loaded infrastructure:** Rather than waiting to address system constraints once they reach near maximum loading (e.g 95% loading), the Company could target locations that are not currently constrained but expected to be constrained in the future (e.g 75% loading feeders) which would have lower risk of being overloaded if the market can't respond to the full need.

Q63 Is it possible for the Company to conduct demonstrations on a flexibility market in the near-term?

A. Yes. We do not need to repeat the decade of incremental, manual steps taken in the UK. National Grid has already leapfrogged this learning curve by bringing the Piclo Flex platform into Massachusetts and New York to manage its NWS and Commercial System Relief Programs.[162] By adopting an independent flexibility marketplace platform today, National Grid is skipping the manual RFP phase and moving directly to automated, locational procurement. The Company should

[162] National Grid US, Independent Marketplace for Non-Wires Alternatives (Piclo Flex). https://www.canarymedia.com/articles/virtual-power-plants/massachusetts-national-grid-piclo-marketplace-grid-costs

follow National Grid's lead by evaluating similar digital solutions to test and scale a "Flexibility First" grid.

Q64 What is your recommendation?

A. If PURA approves a version of the TSP, I recommend the proposed Grid Compensation Fund be approved conditional on the following:

- The Company commits to evaluating the grid services procurement process and allocate funds to testing a flexibility market platform

- The Company commits to a midpoint milestone (i.e., 2 years into implementation) where they will work with stakeholders to iterate on and develop a scalable grid services framework inclusive of an updated compensations framework

- The Company consolidates its filings into a single annual filing that will serve as a broader update on the Company's progress towards a flexibility first approach that addresses DERMS, dynamic flexible interconnection and DER distribution grid services

<u>Advancing Forecasting Tools & Circuit Planning Capabilities to manage planning models</u>

Q65 Please describe the scope of the proposed investment.

A. The Company requests a total of $15 million[163] collectively for Advancing Forecasting Tools & Circuit Planning Capabilities to manage planning models. Advanced forecasting tools enable the Company to generate forecasted 8760 load shapes across all levels: substation, transformer, and at circuit levels.[164] Such

[163] $8 million for Advanced Forecasting and $7 million for Circuit Planning Capabilities to manage planning models.
[164] Exhibit CLP-TSP-3, at 138.

profiles are useful for evaluating and sizing certain solutions (e.g., battery storage as an NWA, for which the Company can and does create 24-hour load profiles).[165] Circuit planning capabilities provide the compute resources to allow the modeling and simulation of granular models with 8760 data under various scenarios for every circuit and circuit configuration.[166]

Q66 Please describe your position on this investment.

A. As the Company states, these investments are proposed to align with Integrated Distribution System Planning ("Authority's Version") from 2025 in Docket No. 21-05-15RE03. These capabilities will be critical to transitioning to a flexible, cost-effective grid and especially to implement the granular forecasting necessary to implement dynamic flexible interconnection (i.e., forecasting expected curtailment) and DER grid services (i.e., forecasting not only the magnitude but duration of load constraints). However, while the Company does indicate it will take 12-18 months for the tools to be in full production, it does not detail where and when forecasting can be implemented.

Q67 How could the Company implement advanced forecasting to drive benefits as quickly as possible?

A. Upon deployment of these tools, the Company should focus on implementing these tools at locations with expected DER and load constraints to support the implementation of dynamic flexible interconnection and DER distribution grid services. Specifically, where forecasting is initially implemented should be informed by locations identified as part of implementing dynamic flexible interconnection, the Grid Compensation Fund and the DERMS rollout.

[165] OCC-587, (b), at 2.
[166] Exhibit CLP-TSP-3, at 139.

Moreover, the Company states it currently develops load forecasts only at the substation level,[167] which are determined from 15 min SCADA data by substation and at the system level[168]. The rollout of AMI should provide sufficient data to support advanced forecasting at the feeder level. Thus, the locational development of forecasts should also be coordinated with the AMI rollout such that the forecasting tools can leverage AMI to develop feeder level forecasts on an iterative basis as AMI is deployed regionally.

Q68 What is your recommendation?

A. If PURA approves a version of the TSP, I recommend the proposed Advancing Forecasting Tools & Circuit Planning Capabilities be approved conditional on the following:

- The Company begins advanced forecasting in an iterative manner once tools are available and be informed by locations identified as part of implementing dynamic flexible interconnection, the Grid Compensation Fund and the DERMS rollout.

If the Authority approves AMI deployment in this rate case, the Company will coordinate its deployment with AMI such that AMI prioritizes deployment at locations that can support advanced forecasting.

Shared Hosting for Advancement of Renewable Energy (SHARE)

Q69 Please describe the scope of the proposed investment.

A. The Company requests $47.6 million within this TSP term to implement SHARE which is the Company's proposed approach to resolving DER substation saturation and queue stagnation due to the current cost-causation principle for

[167] OCC-574, (a), at 1.
[168] OCC-575, (a), at 1.

DER interconnections and accompanying free-ridership issues and locations with high DER growth potential and insufficient electrical infrastructure to accommodate large-scale DER. The Program would study DER at groups of interdependent substations and develop group solutions to: 1) integrate the stalled DER safely and reliably within a fixed timeframe; 2) equitably allocate group solution costs between current and future DER and load customer, who benefit from increased capacity and reliability; 3) solve the free-ridership problem by instituting a fixed $/kW fee for current group members and all future DER that would subscribe to the solution; 4) provide cost-certainty for current and future developers; and 5) enable future DER growth by providing additional capacity due to use of standard-size equipment. [169] The Company has identified investments that would enable over 300 MW of DER while supporting capacity and reliability needs for 6 substations.[170]

Q70 Please describe your position on this investment.

A. I strongly oppose this as investment as it is premature, carries significant ratepayer risk and has not been properly vetted by stakeholders. Specifically, I have the following concerns:

- **Does not consider a flexibility first approach:** Locations that are at or will be at their limit for DER hosting capacity are the ideal candidates to implement dynamic flexible interconnection. The Company states it has not evaluated utilizing dynamic flexible interconnections to defer the upgrades proposed for the SHARE program.[171]

- **Methodology and existing implementations carry significant ratepayer risk:** The SHARE program appears to resemble the Massachusetts Capital Investment Proposal ("CIP"), which has been under

[169] Exhibit CLP-TSP-1, at 60-70.
[170] Exhibit CLP-TSP-3, at 143.
[171] OCC-583, (b), at 1.

implementation for several years. As described below, I have significant experience with this program and outline the risks to the methodology and status of the implementations to date.

- **Program is premature and has not considered stakeholder input:** While the Company is requesting $47.6 million in the TSP term, the proposed investments appear to total $275 million[172]. SHARE is inherently a proactive investment proposal, and similar frameworks have or are continuing to undergo significant vetting in Massachusetts, New York, Minnesota and California. Even if SHARE represents a reasonable framework, there should be a process to vet and ultimately approve such a framework.

Q71 Please elaborate on how SHARE does not consider a flexibility first approach.

A. A flexibility first approach ensures that flexibility solutions are considered first prior to traditional capital investments. Locations with zero or limited firm DER hosting capacity are perfect locations to implement dynamic flexible interconnection, fully utilize the system and integrate additional DERs.

The Company states the SHARE program and dynamic flexible interconnection target different needs for DER developers and the Company with the SHARE program intended to target larger DER development in more rural areas where the available real estate for DER exceeds the load in the region and flexible interconnection program intended to target underutilized hosting capacity.[173] This is a false dichotomy as dynamic flexible interconnection can target underutilized hosting capacity in regions supporting larger DER development. In fact, this is the most common use case for dynamic flexible interconnection. In Massachusetts,

[172] Exhibit CLP-TSP-3, at 146-149.
[173] OCC-583, (b), at 1.

the Company proposed $239 million in investments similar to those included under SHARE to enable DER capacity. In my testimony, I provided an alternative analysis that dynamic flexible interconnection could not only defer the proposed investment but enable more DER capacity.[174] Massachusetts approved $753 million in CIPs partially since dynamic flexible interconnection was in its infancy at the time of these proposals. Connecticut can avoid this dilemma by first maximizing the amount of additional DERs that can be integrated via dynamic flexible interconnection and then only consider additional investment.

Q72 Please elaborate on how the proposed methodology and existing implementations carry significant ratepayer risk.

A. The methodology proposed inherently requires ratepayers to pay for a portion of the proposed investments given that DERs on their own cannot financially support these upgrades. While the Company claims that these investments will benefit customers, the assumptions behind these claims are highly speculative in nature. Specifically, the Company primarily uses a 2050 electrification forecast to account for the benefits for customers. Such a forecast is highly speculative given that the forecast projects out over 20 years and the fact that assumptions around electrification could drastically change in that time period. Moreover, the benefits calculation allocates cost without accounting for the fact that customers are likely to not benefit from the investment (i.e., the timing by which electrification and load growth would have triggered such an investment) till much later. It is unclear what are the appropriate flexibility assumptions or planning criteria that should be used when sizing these investments. My testimony and several intervenors in Massachusetts have called for various flexibility assumptions and the relaxing of planning criteria to ensure any proposed investments would be as efficient as

[174] D.P.U. 25-30/-81/-82/-83, Direct Testimony of Nikhil Balakumar on behalf of the Massachusetts Attorney General's Office, November 14 2025. https://d3i1pf1zzeh4ol.cloudfront.net/26fc0d85-1530-4ea9-b62a-47386c75bf42.pdf

possible.[175] Finally, it is unclear whether the current investments will be fully subscribed by DERs creating the risk of stranded assets. Significant portions of the Company's ongoing investments have yet to be subscribed[176], have experienced group study drop outs[177] and there is further uncertainty with the expiration of the Investment Tax Credit ("ITC").

Q73 Please elaborate on the importance of stakeholder input for any proactive planning framework.

A. As demonstrated above, there is both significant complexity and risk in developing proactive investments. Such frameworks should be developed carefully with stakeholder input and leverage lessons learned from other jurisdictions. Moreover, the Massachusetts Department of Public Utilities is currently considering an updated framework that builds upon the Company's current proposal. Given that the Company can focus on enabling additional DERs via dynamic flexible interconnection, this provides Connecticut time to consider rulings in Massachusetts and other jurisdictions to inform a future proactive planning framework.

Q74 What is your recommendation?

A. I strongly recommend PURA reject the Company's proposal and explicitly require it to first leverage dynamic flexible interconnection in areas of high DER development with limited hosting capacity. If PURA wishes to establish a proactive planning framework, I recommend that a separate stakeholder process

[175] D.P.U. 25-20, Direct Testimony of Nikhil Balakumar on behalf of the Massachusetts Attorney General's Office, May 6 2026, at 14-23. https://d3i1pf1zzeh4ol.cloudfront.net/530ad5f2-aaea-437e-8c2f-0ee4826b5599.pdf

[176] D.P.U. 25-30/-81/-82/-83, Direct Testimony of Nikhil Balakumar on behalf of the Massachusetts Attorney General's Office, November 14 2025, at 65. https://d3i1pf1zzeh4ol.cloudfront.net/26fc0d85-1530-4ea9-b62a-47386c75bf42.pdf

[177] D.P.U. 25-30/-81/-82/-83, Direct Testimony of Nikhil Balakumar on behalf of the Massachusetts Attorney General's Office, November 14 2025, at 49. https://d3i1pf1zzeh4ol.cloudfront.net/26fc0d85-1530-4ea9-b62a-47386c75bf42.pdf

be established to develop such a framework and incorporate lessons learned from other jurisdictions.

IV. ADVANCED METERING INFRASTRUCTURE

Q75 Please describe the Company's proposed investment.

A. The Company is proposing an accelerated, systemwide deployment of AMI that would be implemented over six years with a total cost of $1.253 billion.[178] The Company states AMI is the preferred replacement solution to ensure that the Company is able to manage its distribution system effectively and safely for its customers while providing the advanced capabilities that are necessary to achieve Connecticut's energy, environmental, and affordability goals.[179] There are several key components to this proposal:

- **Broad set of benefits identified:** The Company identifies a broad set of benefits that will be enabled with AMI including power outage restoration, bulk data sharing, energy efficiency and demand management analytics, load research, transformer load management analytics, unbilled usage detection, Volt/Var Optimization ("VVO") analytics, remote connect/disconnect functionality, advanced billing capabilities, VVO, and comprehensive TLM.[180] Moreover, the next generation meters have distributed intelligence capabilities which enables a broader set of capabilities.[181]

- **Benefits will be enabled iteratively for certain benefits:** The Company states several capabilities can be realized with the commencement of AMI

[178] Exhibit CLP-AMI-2, at 3-4.
[179] Exhibit CLP-AMI-2, at 3.
[180] Exhibit CLP-AMI-2, at 3-4.
[181] Exhibit CLP-AMI-2, at 22.

meter deployment while others can only be fully realized after the full deployment of AMI.[182]

- **Deployment will leverage Public Carrier Cellular Networks:** In contrast to traditional deployments, the Company proposes to not only use a mesh network but pair it with public carrier cellular networks to serve as the communications backbone to transmit AMI data.[183]

- **Concurrent, Regional Deployments:** The Company proposes parallel East/West deployment teams to balance rural and metro work.[184]

Q76 Please describe your position on the proposed investment.

A. I believe AMI can serve as a foundational investment for grid modernization and transitioning to a flexible, cost-effective grid but only if it's implemented in a manner that fully utilizes the technology to maximize all its benefits and do so as quickly as possible. The Company's proposal represents a good starting point to realize this vision. However, there are several gaps in the proposal that the Company should address:

- **Comprehensive Data Platform:** The Company proposes a data access platform that allows authorized third parties to access customer data. However, this proposal misses certain key data and reporting requirements and does not address the broader role of data access to support DER integration and utilization.

- **Iterative 8760 Profile Rollout:** The Company intends to use AMI meters to create 8760 profiles.[185] However, it is unclear when these profiles will

[182] Exhibit CLP-AMI-2, at 3-4.
[183] Exhibit CLP-AMI-2, at 16-17
[184] Exhibit CLP-AMI-2, at 11.
[185] OCC-743, (c), at 2.

be developed as part of the existing roadmap and how this will be coordinated with the proposed advanced forecasting & planning tools as well as DERMS.

- **Strategic Deployment to Target System Constraints:** The Company proposes parallel East/West deployment teams to balance rural and metro work but does not appear to consider how a locational deployment could accelerate the transition to a flexibility first approach.

- **Detailed Distributed Intelligence Pilot:** The Company commits to evaluate distributed intelligence capabilities[186] but does not provide a concrete pilot or plan on how such capabilities will be used to support planning and operations.

- **Detailed Evaluation of Real-time AMI Data:** The Company is currently investigating how AMI could support real-time systems such as ADMS & DERMS as well as Voltage Optimization given that a public carrier cellular network is incorporated into the communications architecture. However, there are no milestones in the current plan for when this evaluation will be complete and reported on.

Comprehensive Data Platform

Q77 Please elaborate on your position on a comprehensive data access platform.

A. Automated, digitized, application programming interface ("API") based customer data access is critical to DER integration and utilization, especially when it comes to scoping DER solutions, enrolling customers in programs, and ultimately being able to settle in various energy markets. The Company's proposal provides a strong foundation to address these issues in explicitly centering its strategy around

[186] OCC-748, at 1.

a Green Button Connect protocol and API-based architecture. I provide minor recommendations to incorporate certain lessons learned from other jurisdictions below.

However, DER integration and utilization not only requires automated, digitized, API based access to customer data (i.e. upon customer authorization), but also system data and rates/tariff information. DER providers and aggregators often need to use this data together to enable a broad set of use cases including DER and EV charging integration, enrollment and settlement in various programs. As such, this data should be accessible together and in a modern, scalable manner. The figure below outlines the core set of use cases, data needed and the associated benefits.

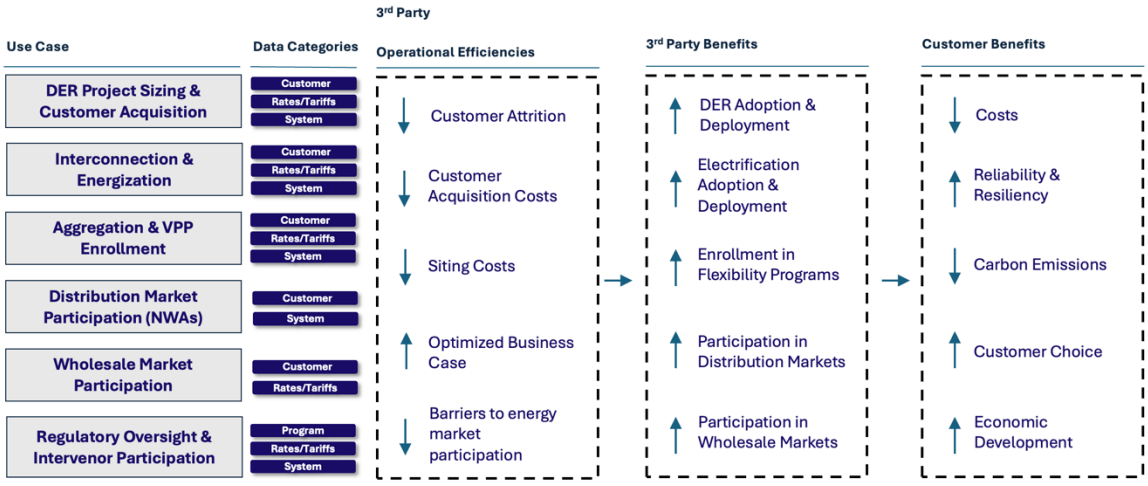


Figure 8: Comprehensive Data Platform: Use Cases, Data Needs & Benefits

The Company acknowledges this, stating the platform can support future expansion and additional use cases including DER programs, demand response initiatives and additional authorized customer energy data services approved

through future regulatory proceedings.[187] I provide recommendations on how the Company can take steps towards this vision below.

Q78 What modifications do you propose to the Company's existing proposal for a customer data access platform that leverages the Green Button Connect standard?

A. I propose two modifications: 1) providing access to raw meter usage data and enrolled programs; and 2) including and publishing additional metrics to report on platform performance. The Company states it will provide access to: (1) Customer account and service information; (2) Billing-quality usage data, including validated consumption and demand information; (3) Interval usage data from AMI meters; and (4) Supplier and service relationship information. However, the Company states it anticipates providing validated, estimated, and edited ("VEE") billing-quality AMI data rather than raw meter data.[188] Moreover, while the Company will provide the "rate class/rate code," it does not appear to provide any other programs the customer may be enrolled in. Raw meter usage data has been identified in several regions including MISO for Ameren Missouri & Illinois[189] and PJM for ComEd[190] as critical to support DER aggregator settlement in wholesale markets. Specifically, billing quality is often not available quickly enough to support initial settlement submission requirements, hence the need for raw meter usage data. Moreover, customer program data was also identified and scoped into the data requirements by the same utilities as this will be critical to inform what programs DER providers and aggregators can enroll customers in and avoid conflicts where possible.

[187] OCC-742, (e), at 5.
[188] OCC-742. (a)(3), at 3.
[189] Ameren Illinois 2028-2031 Integrated Grid Plan, January 20, 2026, at 111. https://icc.illinois.gov/docket/P2026-0051/documents/375149/files/657593.pdf
[190] ComEd, Integrated Data Platform: Proposed Implementation Plan , December 20, 2024, at 7. Integrated Data Platform: Proposed Implementation Plan

Regarding metrics, the Company proposes tracking (1) API transaction activity, (2) Data request volumes, (3) Request completion status, (4) Successful and failed transactions, (4) Error reporting and exception tracking and (4) User activity and transaction history. I support these metrics but also recommend the Company track total number of registrants; the average time it takes for the Company to approve a registration request; and platform uptime. Legacy platforms often take unreasonable amounts of time to approve registration requests, causing third parties to miss windows for various deadlines including wholesale market settlement. Finally, the Company should publish these metrics publicly on the platform so there is transparency in platform performance.

Q79 What steps can the Company take to support an expanded vision for the data platform?

A. Data access is often addressed in silos across a broad set of venues and proceedings, which often leads to siloed and one-off solutions. The Company should view this platform as a one-stop shop for future data access, provided that it is cost effective and valuable to provide such data on an ongoing basis. Specifically, system data and rates/tariff information have been identified by both ComEd[191] and Ameren[192] as high priority and complimentary datasets to customer data to support DER integration and utilization. While the Company has hosting capacity maps[193], these maps (1) don't provide sufficiently granular data and (2) don't provide API access to such data limiting the usefulness of the platform. ComEd has committed to providing a comprehensive set of system data from the hosting capacity values all the way down to the underlying data, including 8760 profiles and the system model as shown below.

[191] ComEd has proposed an Integrated Data Platform including all three data types as part of their Multi-Year Integrated Grid Plan.

[192] Ameren is currently scoping and has committed to propose an Integrated Data Platform to include all three data types.

[193] https://www.eversource.com/residential/about/doing-business-with-us/interconnections/connecticut/connecticut-hosting-capacity-map

DATA		USE CASE	GROUP
Type	Description		
8760 profiles	Hourly load profiles of electrical grid components	• Managing behind-the-meter systems • Flexible interconnection • Managing grid-level load • Evaluating load management effectiveness • Planning and forecasting • Forecasting, such as demand response and load forecasting	Solar / Storage Solar / Storage EV / EVSE EV / EVSE EV / EVSE Aggregators / ESCOs
Hosting capacity map	Information on the capacity of the electric grid to accommodate additional DERs	• Developing systems tailored to grid capabilities • Siting new projects and making sound interconnection decisions • Determining if an EV charging project is feasible for a location • Targeting customers • Helping customers avoid invalid interconnection requests	Solar / Storage Solar / Storage EV / EVSE Aggregators / ESCOs Aggregators / ESCOs
Interconnection queue data	Information on interconnection projects connecting to the electric grid	• Developing systems tailored to grid capabilities • Siting new projects and making sound interconnection decisions • Determining if an EV charging project is feasible for a location • Targeting customers • Helping customers avoid invalid interconnection requests	Solar / Storage Solar / Storage EV / EVSE Aggregators / ESCOs Aggregators / ESCOs
Upcoming investments	Information on upcoming capital investments in electric grid infrastructure	• Siting new projects and making sound interconnection decisions • Targeting customers • Monitoring additional investments for the worst-performing wards to support policy objectives	Solar / Storage Aggregators / ESCOs NGOs / PI Groups

DATA		USE CASE	GROUP
Type	Description		
Interconnection pre-application report data	Information that helps to outline the feasibility and requirements for connecting new projects to the grid	• Developing systems tailored to grid capabilities • Siting new projects and making sound interconnection decisions • Determining if an EV charging project is feasible for a location • Targeting customers • Helping customers avoid invalid interconnection requests	Solar / Storage Solar / Storage EV / EVSE Aggregators / ESCOs Aggregators / ESCOs
Reliability data	Information related to the performance and dependability of the electric grid	• Monitoring additional investments for the worst-performing wards to support policy objectives	NGOs / PI Groups
System model / circuit layout	Detailed representations of the electric grid's physical and operational characteristics	• Developing systems tailored to grid capabilities • Siting new projects and making sound interconnection decisions • Targeting customers • Helping customers avoid invalid interconnection requests	Solar / Storage Solar/Storage || EV/EVSE Aggregators / ESCOs Aggregators / ESCOs

Figure 9: ComEd Integrated Data Platform: System Data Requirements[194]

Granular access to such data via an API drives several benefits as identified by the Illinois DER industry[195]:

- **Precise and cost-effective siting:** Developers often apply to interconnect in a location based on limited hosting capacity map information, which results in the application being rejected or requiring unexpected and cost prohibitive upgrades, which in turn leads to the application being withdrawn. This process wastes significant time and financial resources of both the developer and ComEd, and ultimately leads to slower deployment of clean energy to support the General Assembly's ambitious clean energy

[194] https://icc.illinois.gov/docket/P2022-0486/documents/359481/files/629728.pdf
[195] Direct Testimony of Kate Tohme, Solar Energy Industries Association, Coalition for Community Solar Access and Illinois Solar Energy & Storage Association, July 16, 2026, at 15-17. https://icc.illinois.gov/docket/P2026-0047/documents/383840/files/675987.pdf

and DER deployment goals. The proposed data requirements would allow developers to better understand and anticipate system constraints and reduce surprises upon application.

- **Minimize infeasible interconnection requests:** Limited data results in imprecise interconnection requests, ultimately requiring ComEd to review large amounts of applications that never interconnect due to the application being rejected or requiring cost prohibitive upgrades. By enabling more precise siting, ComEd will be less burdened with infeasible interconnection requests and can reallocate their resources to process viable applications.
- **Distribution grid services and non-wires alternatives:** Access to the proposed data also supports the scaling of distribution grid services by giving DER developers sufficient information to understand how and if they can relieve distribution constraints through new proposed DERs and thus submit more robust non-wires alternatives or grid services proposals.
- **Application Programming Interface (API):** Allows developers to pull data into their own systems to inform development decisions. This is opposed to the existing hosting capacity maps which do not provide a way to efficiently access and use the underlying data.

As such, the Company should commit to leveraging this platform as a one-stop shop for future data access and propose solutions to integrate system and rates/tariff information into such a platform.

Iterative 8760 Profile Rollout

Q80 Please elaborate on your position regarding an iterative 8760 profile rollout.

A. The Company intends to use AMI meters to create 8760 profiles.[196] However, it is unclear when these profiles will be developed as part of the existing roadmap and

[196] OCC-743, (c), at 2.

how this will be coordinated with the proposed advanced forecasting & planning tools as well as DERMS. As previously stated in Section V, 8760 profiles are critical to transitioning to a flexible, cost-effective grid and especially to enable key use cases like dynamic flexible interconnection and DER distribution grid services. Moreover, data to create 8760 profiles is a key dependency for the advanced forecasting & planning tools and DERMS. Given that the Company states several capabilities can be realized with the commencement of AMI meter deployment and that such meters are deployed regionally, the Company should in theory be able to enable 8760 profiles iteratively as sufficient AMI is deployed and can be aggregated to develop 8760 profiles at the feeder and substation.

Strategic Deployment to Target System Constraints

Q81 Please elaborate on your position on the strategic deployment of AMI to target system constraints.

A. The Company proposes parallel East/West deployment teams to balance rural and metro work but does not appear to consider how a locational deployment could accelerate the transition to a flexibility-first approach. Ideally, this deployment could be done in such a way that AMI iteratively enables 8760 profiles but does so in locations that have or are anticipated to have DER and load constraints. Fortunately, the Company's approach to balance rural and metro work aligns with this approach as DER and load constraints are typically in rural and metro areas respectfully. The Company should use the locations it identified to prioritize dynamic flexible interconnection, the DER compensation fund and DERMS deployment to inform where AMI should first be strategically deployed.

Well Defined Distributed Intelligence Pilot

Q82 Please elaborate on your position on a well-defined distributed intelligence pilot.

A. The Company commits to evaluating distributed intelligence capabilities[197] but does not provide a concrete pilot or plan on how such capabilities will be used to support planning and operations. These capabilities have significant potential and have yet to be fully utilized in ongoing deployments. This is why a thoughtful approach that explores specific use cases and allows iteration on these solutions with vendors is critical. Moreover, the Company's proposed architecture to leverage public carrier cellular network also creates new potential to leverage these capabilities combined with distributed intelligence to unlock new use cases for real-time operations. The Company should propose a concrete distributed intelligence pilot with specific use cases within 1 year of approval of the AMI deployment.

Evaluation of Real-time AMI Data Use Cases

Q83 Please elaborate on your position on an evaluation of real-time AMI data use cases.

A. The Company is currently investigating how AMI could support real-time systems such as ADMS & DERMS as well as voltage optimization, given that a public carrier cellular network is incorporated into the communications architecture. Specifically, the Company is evaluating potential future integrations with real-time systems including ADMS and DERMS but these are not included in the Company's implementation plan.[198] Moreover, the Company is currently investigating the technical feasibility, costs, and benefits of an AMI-informed DMS model, including the benefits for voltage optimization. Issues of data

[197] OCC-748, at 1.
[198] OCC-745, (a)(ii), at 2.

latency will be included in this investigation.[199] AMI provides the most granular data available on the system and should be leveraged where possible to support not just billing but planning and operations. Specifically, there may be potential to defer or eliminate the needs for other sensor investments if AMI can truly be integrated into real-time operations. I support this investigation and request that the Company also investigate the potential of AMI to defer or replace sensor investments and report on its progress as part of any reporting supporting the ongoing deployment.

Q84 What is your recommendation?

A. I recommend the Company's proposed AMI investment be approved conditional on the following requirements:

- The Company should be required to also a) provide access to raw meter usage data and enrolled programs and b) include and publish additional metrics to report on platform performance as described above.

[199] OCC-747, (a), at 1.

- The Company should be required to commit to leveraging this platform as a one-stop shop for future data access and propose solutions to integrate system and rates/tariff information into such a platform.

- The Company should be required to iteratively enable 8760 profiles at feeders and substations as sufficient AMI is deployed at specific regions.

- The Company should be required to use the locations it identified to prioritize dynamic flexible interconnection, the DER compensation fund and DERMS deployment to inform where AMI should first be strategically deployed and enable 8760 profiles in these regions.

- The Company should be required to propose a concrete distributed intelligence pilot with specific use cases within 1 year of approval of the AMI deployment.

- The Company should be required to include an evaluation of the potential of AMI to defer or replace sensor investments as part of investigating how AMI can support real-time operations and report on the progress of this investigation as part of ongoing AMI updates.

V. IN-SERVICE INVESTMENTS

A. Purpose and Overview

Q85 What is the purpose of this portion of your testimony?

A. This portion of my testimony addresses the Company's request to include in rate base the capital additions it placed in service from January 1, 2017, through December 31, 2025, and its request to include planned plant additions for 2027 through the end of the Rate Year in rates. I rely on the joint testimony of the Company's Additions Panel, the project-level data in its exhibits, and the

Company's responses to interrogatories. I examine whether specific additions were prudent: whether the Company made reasonable decisions about what to build, how to build it, and how to account for it, and whether it had reasonable documentation, vetting and approval processes in place before committing the funds. Where my testimony on the TSP Plan already addresses an issue, I refer to it rather than repeat it.

The Company states that it placed approximately $4.3 billion of capital additions in service over this eight year period, and that the costs "were reasonably and prudently incurred."[200] Of the $4.318 billion of net distribution additions, $2.290 billion, or 53 percent, was placed in service through annual programs and annual work orders rather than individually authorized projects.[201] The Company also asks to include in rates $847.8 million of planned additions for January 2026 through June 2027 and $664.9 million for the Rate Year ending June 30, 2028.[202]

Q86 What must the Company show to demonstrate the additions were prudently incurred?

A. The Company bears the burden of demonstrating that each addition is used and useful and that its cost was prudently incurred. That is, the decision to undertake the work, and the cost of carrying it out, must have been reasonable in light of what the Company knew or should have known at the time.[203]

I have concerns with the prudency of several of the Company's additions. My review identifies two groups of additions for which the record does not support a finding of prudence, and several areas where the record does not yet contain the information needed to complete the review:

[200] Exh. CLP-ADDITIONS-1 at 445.
[201] Exh. CLP-ADDITIONS-2; Exh. CLP-ADDITIONS-3.
[202] Exh. CLP-ADDITIONS-1 at 52.
[203] Conn. Gen. Stat. §§ 16-19e(a) and 16-22.

- **Capacity additions:** The Company placed $145.4 million of Peak Load/Capacity projects in service from 2023 through 2025. The record does not contain the project-level evaluation of non-wires alternatives that the Company's own planning procedures, and PURA's November 2022 Non-Wires Solutions decision, contemplate for investments of this kind.

- **Direct-buried cable:** Proactive replacement of direct-buried cable cost about $257 million. The cost per mile tripled, and the Company has since scaled the approach back in favor of repair. The Company has not shown that the proactive replacement approach it adopted in 2019 produced benefits commensurate with its cost, and the record contains no benefit-cost analysis supporting that approach or its continuation as unit costs rose.

- **Areas pending Company data:** Capacity additions placed in service without a documented evaluation of lower-cost alternatives; the proactive direct-buried cable replacement program; capitalized storm restoration from the 2018–2023 storms; capitalized storm restoration from the 2018–2023 storms; AMR meter additions; and resiliency programs with no measured storm benefit. The record does not yet contain enough information to determine whether these additions were prudently incurred. I will update my recommendations in surrebuttal testimony and final positions on the prudency of plant will be based on the actual amounts the Company documents and supported through the close of record.

Beyond these specific items, the record shows weak cost control over the overall portfolio. Spending exceeded the Board-approved plan in seven of eight years. I recommend a specific adjustment for direct-buried cable, documentation requirements for the capacity additions and the areas pending Company data, and a limit on the planned plant additions included in rates.

Q87 How does actual capital spending compare with the plans approved by the Company's Board, and what does that show about cost control?

A. Connecticut Distribution capital spending exceeded the plan in the Company's annual Capital Book in seven of the eight years from 2017 through 2024, by a cumulative $350.8 million, or 11 percent (Table 1).

Table 4: Connecticut Distribution Capital Spending, Plan Compared with Actual ($ million) [204]

Year	Plan	Actual	Variance	Variance (%)
2017	336.0	359.0	+23.0	+6.8%
2018	325.0	409.0	+84.0	+25.8%
2019	360.0	417.0	+57.0	+15.8%
2020	371.0	402.0	+31.0	+8.4%
2021	365.0	409.0	+44.0	+12.1%
2022	434.0	469.9	+35.9	+8.3%
2023	466.4	557.9	+91.5	+19.6%
2024	466.2	450.6	-15.6	-3.3%
2017–2024	**3,123.6**	**3,474.4**	**+350.8**	**+11.2%**

The overruns did not come from individual projects costing more than estimated. For individually authorized projects begun before 2022, actual direct costs were 18 percent below their pre-construction estimates in aggregate, and nearly half came in more than 10 percent under estimate.[205] The overruns came from adding work to the portfolio during the year. For 2023, the year with the largest overrun, the two largest additions were a $22.0 million trip saver program and $20.0 million of circuit patrol fixes, neither of which was in the plan the Board approved.[206]

This has two implications for prudence. First, project estimates that run well above actual costs do not act as a control. A project can absorb scope growth without triggering the supplemental authorization the Company's policy requires. Second, the real control point is the decision to add work to the year's portfolio,

[204] Exh. CLP-ADDITIONS-12 at 8, 28, 45, 65, 83, 102, 121, 145, 167.
[205] Exh. CLP-ADDITIONS-4.
[206] Response to OCC-780.

and that is where the record is thinnest. When requesting the documents authorizing spending above plan, the Company referred OCC to its Capital Books and to total-company variance analyses filed in other dockets. It did not provide or identify any authorization.[207] As I explain in the Sustained Tier section of my testimony, the Company also cut its 2025 plan for "regulatory recovery risk" and stated that the cut had no reliability consequence. Taken together, these facts show that much of the Company's capital work was discretionary in timing and scope. That raises the importance of showing that each addition was selected on its merits.

Q88 Did the Company's reliability and resiliency additions deliver results, and were they properly accounted for?

A. As discussed in the TSP section of my testimony, Blue-Sky SAIDI worsened from 70.7 minutes in 2021 to 77.5 minutes in 2025, while the Company placed $984.6 million of reliability capital in service. It also shows that the Company could not identify the reliability performance it expected when it authorized that capital. I do not repeat that analysis here. For prudence, the more specific problem is what the resiliency portion bought and how it was accounted for.

Of the $984.6 million, $390.4 million was placed in service under System Resiliency/Expanded Reliability.[208] PURA approved System Resiliency for 2018 through 2020, with recovery through the capital tracker. After that approval ended, the Company continued the work and, in 2023, moved it from the Regulatory Commitments category to Reliability. When asked for the reliability benefit measured after completion of each program, the Company provided budget amounts and project listings, not measured benefits.[209]

[207] Response to OCC-779.
[208] Response to OCC-804, Attachment 1.
[209] Response to OCC-802.

The TSP section of the testimony explains that the Company has not measured the storm-day benefits of these programs, even though it states that their benefits "may not be fully reflected in Blue-Sky SAIDI."[210] OCC is requesting storm outage events, customer-minutes interrupted on major event days, and storm restoration cost before and after the work, for the circuits and zones where resiliency work was done. If the Company cannot show a measurable benefit, PURA should deny recovery for any resiliency additions placed in service after its approval ended in 2020 on the basis that they were not prudently incurred.

Q89 Did the Company evaluate lower-cost alternatives before it built the capacity projects placed in service from 2023 through 2025?

A. The record does not contain enough information to make that determination. Peak Load/Capacity spending rose sharply in 2022 and 2023 (Table 2). The Company attributes the decline from 2023 to 2024 to the number of large substation capacity projects (six in 2023 versus three in 2024).[211] In my experience, capacity needs that are modest in size or short in duration are where lower-cost alternatives are most likely to be viable. Load transfers, demand response, energy storage and flexible interconnection can defer or avoid a new transformer or feeder when an overload is small or lasts only a few hours a year.

[210] Response to OCC-804 at 2.
[211] Exh. CLP-ADDITIONS-12 at 121, 145.

Table 5: Peak Load/Capacity Capital, 2017–2025 ($ million) [212]

Year	Plan	Actual spending
2017	26.0	19.0
2018	36.0	38.0
2019	24.0	20.0
2020	21.0	18.0
2021	17.0	27.0
2022	20.0	54.0
2023	58.9	80.0
2024	49.0	45.9
2025	46.1	Not reported
Placed in service, 2017–2025 total	–	278.9
Large substation capacity projects (count)	–	6 in 2023; 3 in 2024

The Company's own procedures call for that evaluation. Its project authorization form includes an "Alternatives Considered" section.[213] Its approval process requires the project initiator to evaluate "the potential use of non-wires alternatives ('NWA') solutions," to prepare cost estimates for the preferred solution and the leading alternative, and to present them to the Solutions Design Committee before a solution is selected.[214] The Company also developed a written Non-Wires Alternative Framework in 2021[215] and states that "since implementation of the new NWA process under Docket No. 24-08-08 Final Decision," it "has been adhering to the process and criteria outlined therein."[216] PURA's November 9, 2022 Non-Wires Solutions decision likewise bases its prudence review on "a contemporaneous record of utility information and decision-making,"[217] as I discuss in the TSP section of my testimony. Because the first formal cycle of that process began only in 2025,[218] and only "[p]rojects approved after January 2025 have undergone the newly established NWA

[212] Exh. CLP-ADDITIONS-12 at 8, 28, 45, 65, 83, 102, 121, 145, 167; Response to OCC-811 at 2 (in-service total). Capital spending and in-service additions are on different bases.
[213] Exh. CLP-ADDITIONS-1 at 19.
[214] Id. at 36.
[215] Response to OCC-578, Attachment 1 at 1.
[216] Response to OCC-578.
[217] Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, Decision (Nov. 9, 2022), Appendix A, Non-Wires Solutions Process Design Document, p. 2.
[218] Id., p. 3.

process,"[219] the screening that applied to the projects at issue was the Company's own.

The record does not show how that screening was applied. OCC asked the Company to identify each substation capacity project undertaken from 2017 through 2025 together with "any non-wires alternative evaluation." The Company's Attachment 1 lists the projects' load forecasts and post-in-service peak loads and references non-wires alternatives, but it does not identify the alternatives considered, their cost relative to the wires solution, or why they were not selected.[220] The Company also describes permanent load transfers as, in many cases, the preferred and "typically substantially lower cost" solution, yet states that "[h]istorically these load transfers were not explicitly tracked."[221] When asked for actual substation capacity violations since 2016, it identified none, stating that "[a]ll substation forecasted violations are mitigated by using pre-contingent load transfers to adjacent substations with remaining capacity."[222]

Without these records, PURA cannot determine whether these projects were the least-cost means of meeting an identified need. Eversource has the burden of demonstrating this for each Peak Load/Capacity project with its own project authorization placed in service from 2023 through 2025, including line capacity projects.

If after further discovery, the record shows that the Company built capacity without evaluating lower-cost alternatives, or that the forecast overloads did not occur, I will recommend that PURA disallow the difference between the cost of the project and the cost of the least-cost alternative.

[219] Response to OCC-590.
[220] Response to OCC-805 and Attachment 1.
[221] Response to OCC-599(b) at 2.
[222] Response to OCC-599(c) at 3.

B. Direct-Buried Cable Replacement

Q90 Was the Company's proactive direct-buried cable replacement program prudent?

A. Direct-buried cable replacement is the clearest example of a proactive program for which the record does not show that cost was tested against the alternative. Historically, the Company repaired direct-buried cable as failures occurred. In 2019, it adopted a proactive approach to "replace and upgrade longer segments of cable around failure points."[223]

The cost per mile more than doubled between 2019 and 2022, while the failure rate on the system changed only modestly. The Company has now changed course. Beginning in 2024, it adopted "a hybrid approach combining proactive replacements with repair work." For 2025, it reduced replacement because it "can maintain safety and reliability in the short run with repairs rather than replacement," and because its "investment approach is changing now based on its experience with the proactive replacement program."[224] Repair was the Company's practice before 2019 and again forms part of its approach today. The record does not contain any analysis, at the 2019 decision or when unit costs rose sharply in 2020 and 2022, comparing full replacement with repair.

I do not suggest that every mile replaced was imprudent. In my view, a prudent utility would have re-evaluated the program when its unit cost doubled. In 2022 and 2023, the Company replaced 67.6 miles at a cost of $76.45 million. At the 2019–2021 average of about $750,000 per mile, the same work would have cost about $50.0 million. PURA should disallow the difference of about $26.5 million, net of any cost increase the Company demonstrates was due to general inflation, unless the Company produces, before the record closes, a contemporaneous

[223] Response to OCC-798.
[224] Responses to OCC-781 and OCC-798.

analysis supporting full replacement at the higher cost.[225] I will update this recommendation in surrebuttal testimony if the Company provides that analysis.

C. Planned Plant Additions for 2026 and 2027

Q91 What does the Company propose for planned plant additions in 2026 and 2027?

A. The Company proposes to add interim and forecasted plant to the Test Year rate base through June 30, 2028. It uses annual forecasted additions of $544.1 million for 2026, $632.1 million for 2027 and $700.5 million for 2028. From those, it derives $847.8 million of interim additions for January 2026 through June 2027 and $664.9 million of Rate Year additions for July 2027 through June 2028.[226] It allocated the annual totals to plant accounts and months "using historical and forecasted information."[227] The forecast is not built from a list of projects with scopes, cost estimates and in-service dates.

The Company does not ask PURA to find these additions prudent now, and anticipates that determination "in the next rate case at such time that those projects are placed in-service." It nonetheless asks that they be included in rates "subject to reconciliation," and ties its proposed PBMRP to "the planned capital investment plan described in the TSP Plan."[228] The Company will update actual in-service additions during this proceeding, through October 31, 2026 in its December 15, 2026 filing,[229]and it is my understanding that the final update will be included in LFE-1.

The forecast is high relative to the Company's record. Net distribution additions averaged $479.8 million a year from 2017 through 2025. The 2027 forecast

[225] Response to OCC-798. OCC calculations.
[226] Exh. CLP-ADDITIONS-1 at 52.
[227] Id.
[228] Exh. CLP-ADDITIONS-1 at 54.
[229] Exh. CLP-ADDITIONS-1 at 51–52.

exceeds every year in that period, and the 2028 forecast is about 11 percent above the previous peak of $629.9 million in 2023 (Table 4).

Table 6: Net Distribution Plant Additions, Actual 2017–2025 and Company Forecast 2026–2028 ($ million) [230]

Year	Additions	Basis
2017	375.6	Actual
2018	426.1	Actual
2019	425.6	Actual
2020	466.4	Actual
2021	413.7	Actual
2022	478.2	Actual
2023	629.9	Actual
2024	527.4	Actual
2025	575.1	Actual
2017–2025 average	**479.8**	**Actual**
2026	544.1	Interim
2027	632.1	Forecast
2028	700.5	Forecast

Q92 Has the Company supported including these planned additions in rates?

A. No. PURA has consistently declined to set rates on forecasted plant that is not yet in service and used and useful by the close of the evidentiary record in a given single rate year case. In UI's most recent electric rate case, it included only plant found to be used and useful, explaining that "it is an impossibility to provide sufficient evidence that a future plant addition is used and useful and that the investment was prudent."[231] In the CNG and SCG rate case, it allowed only plant completed and in service through the last supplemental filing before the record closed, and found the companies' reconciliation mechanism insufficient to protect ratepayers.[232]

[230] Exh. CLP-ADDITIONS-2 (2017–2025 net distribution plant in service additions); Exh. CLP-ADDITIONS-1 at 52 (2026–2028 annual forecasted capital plant additions).
[231] Docket No. 22-08-08, Application of The United Illuminating Company to Amend Its Rate Schedules, Decision (Aug. 25, 2023).
[232] Docket No. 23-11-02, Applications of Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company to Amend Their Rate Schedules, Decision (2024).

The Company's request raises the same concerns. It seeks no prudence finding now, its reconciliation would apply only downward and only to overall plant in service,[233] and much of its 2027 and all of its 2028 forecasts are tied to the TSP and PBMRP, which OCC recommends PURA not approve.[234] PURA should therefore include in rate base only plant completed, in service and documented through the Company's final supplemental filing before the record closes, and exclude all forecasted additions. My recommendations on plant will be finalized based on that filing.

D. Conclusion

Q93 Please summarize your recommendations.

A. I recommend that PURA:

- Direct-buried cable: Disallow about $26.5 million of 2022–2023 replacement costs above the 2019–2021 unit cost, net of demonstrated inflation, absent a contemporaneous analysis supporting full replacement.
- Areas pending Company data: Require the Company to provide, before the record closes, the information OCC is requesting on capitalized vegetation work, the proactive direct-buried cable replacement program, capitalized storm restoration from the 2018–2023 storms, AMR meter additions, and the measured benefits of the resiliency programs. I will provide my recommendations on these additions in surrebuttal testimony.
- Capacity additions: Require the Company to produce, before the record closes, the contemporaneous evaluation of non-wires alternatives, the load forecast and the authorization documents for each Peak Load/Capacity project placed in service from 2023 through 2025 ($145.4 million), do not find a project prudent

[233] Response to OCC-579.
[234] Exh. CLP-ADDITIONS-1 at 52–54.

where the Company cannot make that showing, and disallow the cost above the least-cost alternative where one was available.

- Resiliency additions: Require before-and-after storm performance data for the resiliency programs, and weigh the absence of measured benefits in deciding whether resiliency additions placed in service after 2020 were prudently incurred.

    - Planned plant additions: Include in rate base only plant additions that are completed, in service and documented as of the last supplemental filing before the record closed, and exclude all forecasted plant. My current estimate is that of the $847.8 million of interim period plant the Company requested from January 2026 through June 2028 approximately $202.5 million will still be forecasted plant at the close of the record and therefore should not be included in rate base, as well as the full $664.9 million requested for the Rate Year. The final position will be based on the actual amounts the Company documents and supported through the late-filing exhibit date/close of record.

These recommendations do not deny the Company recovery of prudent investment. They remove an amount the record shows was not justified, defer a finding where the record does not yet contain the information needed, and they give PURA the record it needs to evaluate the Company's forward capital requests, including the TSP.

VI. STORM COST RECOVERY

E. Purpose and Overview

Q94 What is the purpose of this portion of your testimony?

A. This portion of my testimony addresses the Company's request to recover the incremental costs of 14 storm events that occurred between January 2024 and March 2025. I rely on the joint testimony of the Company's Storm Panel, the

exhibits that support it, and the Company's responses to OCC's interrogatories. I also address the Company's proposed storm-related programs to the extent they relate to storm cost recovery. My testimony focuses on whether the Company's current storm cost recovery framework adequately protects customers from excessive pre-staging, forecast risk, duplicative investments, or costs that are not tied to actual major storm impacts. I also identify additional information PURA may require to determine whether the requested costs were prudently incurred.

Q95 What is your understanding of the Company's request?

A. The Company asks PURA to review approximately $157.3 million in incremental expense for 14 weather events, each of which it states exceeded the $4 million threshold for "catastrophic" storm recovery.[235] The filing also includes costs associated with "eight pre-staging events."[236] Approximately 68 percent of the total cost was for external line and tree crews.[237] As a result, the decision on how many outside crews to bring onto the system before and during each storm is a major driver of the overall request.

Q96 What standard does the Company say applies to these costs?

A. The Company understands that PURA asks whether the Company's decision-making process was in good faith and reasonable under the circumstances at the time the costs were incurred.[238] The Company also states that its Emergency Response Plan ("ERP") and Event Level Matrix ("ELM") "do not prescribe a single, fixed resource plan for each emergency event."[239] The event level, the number of crews secured, and the timing of crew release are therefore judgment decisions. The burden to demonstrate that each of those decisions was reasonable

[235] Exh. CLP-STORM-1 at 8–9.
[236] *Id.* at 80.
[237] *Id.* at 62, 81.
[238] Exh. CLP-STORM-1 at 61.
[239] Response to OCC-545 at 1.

rests with the Company, and that showing should be supported by the contemporaneous record of each event.

Q97 What are your primary concerns regarding the Company's storm costs?

A. Utilities must prepare for and respond to severe weather, and storm costs that Eversource can demonstrate it prudently incurred should be recoverable, but for several of the 14 events, the record does not currently provide enough support to conclude that all of the requested costs were prudently incurred. My concern is that the Company's current approach can allow extraordinary recovery based largely on the amount spent, without clearly showing whether the crews secured in advance were reasonable in light of the storm impacts that actually occurred.

F. How the Events Are Classified

Q98 What is your concern with using a dollar threshold for extraordinary recovery?

A. A dollar threshold by itself can become circular. If a utility mobilizes a large number of external crews before a storm, the related travel, lodging, and standby costs can push the event above the recovery threshold even when the actual reliability impacts are more limited. In that situation, customers may end up bearing costs driven by conservative or excessive storm staffing, rather than solely by the severity of the storm itself.

Q99 Why is that an affordability concern for customers?

A. Storm costs are significant and can vary widely from year to year. The Company reports average storm costs of about $130 million annually,[240] and this proceeding seeks $157.3 million for 14 events over 15 months, with roughly two-thirds of the total attributed to external crews.[241] Under a dollar-based recovery threshold,

[240] Exh. CLP-TSP-3 at 31.
[241] Exh. CLP-STORM-1 at 8–9, 62.

staging more crews can increase both event cost and likelihood that the event qualifies for extraordinary recovery, even if the forecasted damage does not occur. This places much of the forecasting risk on customers. While the company may argue that it adjusts crew levels as forecasts change, such adjustments do not necessarily mean staffing levels are reasonable. Without a clear benchmark linking the number of crews secured to forecasted damage, both initial and revised staffing levels may be excessive. For the six events the Company describes as less severe than forecast, the cost per trouble spot was roughly twice that of the other eight events. Customers should bear this forecast risk only if the Company demonstrates that its staffing, initial and revised, was proportionate to the information available at each decision point

This is especially important because customers are also being asked to fund programs that the Company justifies in part as improving the storm performance. The Company describes its Targeted System Performance tier as one that "[h]ardens the system and reduces storm costs,"[242] states that hardening "reduces the cost and duration of restoration,"[243] and points to expanded distribution automation, storm and outage analytics, and other technologies as supporting future storm response.[244] The Company has not quantified the expected storm-cost reductions from these programs or explained how those savings will be reflected in future storm recovery. Customers should not have to pay for ever-increasing storm recovery while also paying for storm-mitigation programs/investments without a clear way to measure whether those investments are actually reducing storm performance and costs.

[242] Exh. CLP-TSP-3 at 8.
[243] Exh. CLP-TSP-1 at 62.
[244] Exh. CLP-STORM-1 at 77–80; Exh. CLP-TSP-3 at 129.

Q100 Is there an impact-based standard PURA could use instead?

A. Yes, and PURA already has two. Connecticut's Major Storm criterion, established in Docket No. 86-12-03, identifies a Major Storm when the number of locations requiring restoration work in a day exceeds the 98.5th percentile of the Company's most recent four years of data.[245] Additionally, IEEE Standard 1366 identifies a Major Event Day from the Company's own five-year history of daily outage duration. PURA has directed the Company to use both for reliability reporting,[246] and the Company relies on Major Event Days in this docket to describe the purpose of its Targeted System Performance tier and to measure its proposed performance incentives.[247] Both tests measure what the storm did to the system, not what the Company spent.

PURA should use these impact-based tests, coupled with a monetary threshold, to decide which events qualify for extraordinary storm recovery, rather than relying exclusively a monetary threshold. An event that does not qualify under both an impact-based test and a monetary threshold may still have required some prudent spending, but its costs should be treated as normal operating expense unless the Company demonstrates why extraordinary recovery is warranted.

G. What the Company's Own Data Show

Q101 What does the Company's own explanation of its highest-cost storms show?

A. The Company identifies seven storms with a cost per event above its average of $7,489.[248] For six of those seven, the Company explains that the storm was ultimately less severe than the forecast used to stage crews. Those six events are MS24A, MS24B, MS24C, MS24D, MS24H and MS24K. The company describes these events using statements such as "the damage was not as severe as

[245] Decision, Docket No. 17-12-03RE08 (Aug. 31, 2022) at 36.
[246] *Id.* at 55 n.30.
[247] Exh. CLP-TSP-1 at 17, 74, 83.
[248] Exh. CLP-STORM-1 at 64.

anticipated" and "the actual impacts proved less severe than anticipated."[249] For MS24D, the Company states that the cost "reflects the risk profile presented by the forecasts and conditions leading up to the event, rather than the ultimate severity of the weather that occurred."[250] The seventh storm, MS24G, was a fast-moving thunderstorm with little advance warning, and the Company describes widespread damage consistent with the higher cost.[251]

Together, these six events account for about 39 percent of the requested storm costs but only about 22 percent of the trouble spots (5,650 of 25,550). The average cost per trouble spot for these six events was roughly twice that of the other eight events.[252] In other words, a significant share of the requested costs relates to storms where the actual impacts were lower than forecast.

Q102 What should PURA require in those circumstances?

A. PURA should require a forecast-to-actual reconciliation for each storm. The reconciliation should show whether the crews staged were reasonable based on data from previous storms and the information available at each decision point, and should show how quickly the Company adjusted the plan once the actual damage became known.

For each storm, and each point where the Company set or revised its resource plan, the reconciliation should compare:

- forecasted trouble spots and customer outages with actual trouble spots and customers interrupted;
- the declared event level and planned crew levels with the crews actually on the system and the work available to them;

[249] *Id.* at 64–74.
[250] *Id.* at 70.
[251] *Id.* at 70–71.
[252] Exh. CLP-STORM-IMT-2 at 9–22.

- the expected restoration duration with actual restoration time; and
- crew levels at each decision point with crew benchmark for the declared event level and forecasted trouble spots.

The reconciliation should also distinguish the cost of crews that performed restoration work from costs associated with crews that were not ultimately needed, including pre-impact and standby time, travel, lodging, meals, and minimum call-out payments.

Much of this information needed for this review already exists. The UConn outage prediction model provides the Company with "a forecast range of predicted trouble spots";[253] the Company's storm summaries record the expected and actual trouble spots and line resources for each event;[254] and its contractor terms specify a four-hour minimum payment for crews released early.[255] If the data provided indicates that the staffing was not prudent, then PURA should deny the costs associated with the unjustified overspend on that storm.

H. Storm-Related Investments

Q103 Why should the Company's storm-related programs be evaluated together with this request?

A. Because the Company relies on these same storm costs to support several proposed investments. It asks customers to fund a Targeted System Performance tier intended to "[h]arden system & reduce storm restoration costs," along with expanded vegetation management, a storm analytics platform, AMI and further automation.[256] Three connections are important:

- The AMI analysis claims about $352 million in avoided storm costs over 20 years, based on "catastrophic" storms defined by the same $4

[253] Exh. CLP-TSP-3 at 125.
[254] Exh. CLP-STORM-IMT-2 at 8–22.
[255] Response to OCC-554 at 1.
[256] Exh. CLP-TSP-3 at 7–8, 112, 122–129; Exh. CLP-AMI-3 at 65–69; Exh. CLP-STORM-1 at 77–79.

million threshold.[257] If staging costs help push an event above that threshold, they also increase the baseline used to calculate future savings.

- The analytics platform and AMI are both justified in part by improving "procurement, staffing, and prestaging storm crews" and the "procurement of external mutual aid crews." Those are the same types of decisions that drove costs for the six events at issue.[258]

- The Company's positions are difficult to reconcile. It relies on storm-cost savings when seeking funding, but states in this proceeding that cost-effectiveness "is not a concept generally applicable to storm response."[259]

If storm savings are specific enough to support an investment request, they should also be measurable. The storm costs in this filing should therefore serve as the baseline for testing those savings claims.

Q104 What should PURA require before approving those programs?

A. PURA should not approve the Company's storm-related programs and system hardening investments until the Company demonstrates how they will improve its storm response and reduce storm costs for customers. The approval should include measurable performance conditions. The Company should be required to track and report, against the storm costs in this filing, whether the programs: reduce storm response costs; improve forecast accuracy; improve crew staging; reduce restoration time; and reduce customer minutes of interruption (CMI), SAIDI, and customer interruptions. Eversource should also reconcile its storm forecasts with actual results after each event and show how lessons learned are applied to the next one. Claimed benefits should be tied to future recovery. This

[257] Exh. CLP-AMI-3 at 66–69.
[258] Exh. CLP-TSP-3 at 122; Exh. CLP-AMI-3 at 66.
[259] Response to OCC-557 at 1.

is consistent with PURA's resilience framework, which already requires the Company to quantify avoided storm restoration costs.[260]

I. Conclusion

Q105 Please summarize your position.

A. Storm recovery should be impact-based, not exclusively spend-based. Meeting the $4 million threshold alone should not make a storm "catastrophic." I recommend that PURA:

- Add to the monetary threshold an impact-based methodology, to classify the "extraordinary" treatment of storms for cost recovery either using the Connecticut Major Storm criterion and/or IEEE 1366 Major Event Days or any other measure as decided by Connecticut stakeholders.
- When seeking recovery for crew levels that exceed benchmarks for each ELM event level in the ERP, require the Company to demonstrate the reasons at the time and justify the excess, beyond the forecast alone, tied to individual forecasted trouble spots. The Company may exceed a benchmark when conditions require, but should demonstrate the reasons at the time and justify the excess, beyond the forecast alone, when seeking recovery.
- Disallow recovery of the portion of the $62.0 million requested for storms MS24A, MS24B, MS24C, MS24D, MS24H, and MS24K that exceeds established spending benchmarks, absent submission of evidence justifying these variances. Consistent with OCC's prior recommendation, PURA should disallow staffing costs above these benchmarks where the Company has not demonstrated that its storm staging and resource decisions were prudent. This proceeding should establish clear guardrails against excessive storm spending. Customers should pay for prudent storm preparation and restoration, not excessive pre-staging or costs

[260] Decision, Docket No. 17-12-03RE08 at 63–66.

driven by overstated forecasts without demonstrated benefits. For these six events, the Company acknowledged that forecasts overstated storm severity, contributing to higher costs. Our final disallowance on these storms will depend on the subsequent information provided by the Company in the record.

- At a minimum, the Company should reconcile its storm forecasts with actual results and adopt metrics, measured against the storm costs in this filing, for storm response costs, forecast accuracy, crew staging, restoration time and lessons learned from each event.

- Reject the Company's storm-related programs and system hardening investments until the Company demonstrates how it will improve its storm response and reduce storm costs for customers. At a minimum, the Company should reconcile its storm forecasts with actual results and adopt metrics, measured against the storm costs in this filing, for storm response costs, forecast accuracy, crew staging, restoration time and lessons learned from each event.

VII. CONCLUSIONS

Q106 Does this conclude your testimony at this time?

A. Yes, it does.