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

JOINT DIRECT TESTIMONY OF

DONALD J. SCACCO, JR., DIGAUNTO CHATTERJEE AND DOUGLAS P. HORTON

Powering Connecticut's Future
Eversource Leadership Panel

On behalf of

The Connecticut Light and Power Company
d/b/a Eversource Energy

July 14, 2026

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Table of Contents

I. INTRODUCTION.....1

II. THE AFFORDABILITY CHALLENGE.....17

III. OVERVIEW OF THE EVERSOURCE SYSTEM.....39

IV. THE FIVE-YEAR TARGETED SYSTEM PERFORMANCE PLAN.....50

V. THE PERFORMANCE-BASED MULTI-YEAR RATE PLAN.....73

A. The Revenue Deficiency and Its Drivers 79

B. The Proposed PBMRP 83

1. Overview.....83

2. Revenue Cap Formula (I-X) 88

3. Consumer Dividend (S-Factor).....92

4. Earnings Sharing Mechanism 97

5. Exogenous Factor (Z-Factor).....99

6. Capital Support Mechanism.....101

7. Performance Incentive Metrics 103

8. Proposed Review Schedule and Annual Reporting Requirements....118

C. Additional Rate Design Tools..... 119

VI. STORM COST RECOVERY.....121

VII. A BALANCED AND EFFECTIVE PLAN FOR THE FUTURE. 156

VIII. OVERVIEW OF COMPANY WITNESS TESTIMONY.....159

IX. CONCLUSION. 164

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I. Introduction.

Q. Please introduce the Eversource Leadership Panel.

A. The Eversource Leadership Panel is comprised of Donald J. Scacco, Jr., Digaunto Chatterjee, and Douglas P. Horton.

Q. Mr. Scacco, please state your name and business address.

A. My name is Donald J. Scacco Jr. My business address is 107 Selden Street, Berlin, Connecticut.

Q. By whom are you employed and in what capacity?

A. I am the President of The Connecticut Light and Power Company d/b/a Eversource Energy ("CL&P" or "Eversource" or the "Company"). As President of CL&P, I lead a dedicated team committed to meeting the electric-service needs of our Connecticut customers and service communities. In this role, I oversee the day-to-day operations of the electric distribution system and plan for and respond to emergencies, including major weather events.

Q. Please summarize your education and professional experience.

A. I earned an undergraduate degree from St. Anselm College in New Hampshire and a graduate degree from the Mercy College School of Business in New York. I have served at Eversource for over three decades, holding leadership roles in the utility's distribution and transmission businesses, as well as in engineering and customer operations. Prior to my current position, I served as Vice President of Electric Field Operations in Connecticut, overseeing the electric distribution system and projects that improve grid reliability.

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

A. No, I have not.

Q. Mr. Chatterjee, please state your name and business address.

A. My name is Digaunto Chatterjee, and my business address is 107 Selden Street, Berlin, Connecticut.

Q. By whom are you employed and in what capacity?

A. I am Senior Vice President of Engineering for Eversource Energy Service Company ("ESC"). ESC provides centralized services to the natural gas and electric operating subsidiaries of Eversource Energy, including CL&P. In this role, I am responsible for Transmission and Distribution Planning, Transmission, Distribution, Substation and Telecommunications Engineering, Grid Modernization, Asset Management, and Vegetation Management for NSTAR Electric Company in Massachusetts, CL&P in

Connecticut, and the Public Service Company of New Hampshire in New Hampshire. I support day to day operations and new customer connections of the Transmission and Distribution system while also overseeing the development, engineering and design of the 5-, 10- and 20-year Transmission and Distribution ("T&D") Reliability and Resilience Capital Plans.

Q. Please summarize your education and professional experience.

A. In 1999, I received my Bachelor of Science degree in Power Electronics Engineering from Nagpur University in India. I earned a Master's degree in Electric Power Engineering from Rensselaer Polytechnic Institute in 2001 and a Master of Business Administration degree from the University of Chicago-Booth School of Business in 2016. I started my career in 2001 at General Electric Energy Consulting, where I performed engineering studies for U.S. and foreign-based utilities. In 2005, I worked for the Midcontinent Independent System Operator ("MISO") and led Reliability and Economic Transmission Planning as well as Resource Adequacy. While working for MISO, I led the implementation of FERC Orders 890 and 1000; oversaw technical studies in support of the Zonal Capacity Market construct; and led the reliability justification for MISO's Multi Value Projects planned and constructed to enable about 21 GW of onshore wind across the Midwest. In 2016, I worked for General Electric Energy Financial Services as Vice President, Investment Strategy, leading fundamental Energy and Capacity market analysis to inform investment decisions for over 2 GW of renewable generation throughout the U.S. I have also been a member of the Institute

of Electrical and Electronics Engineers ("IEEE") since 2001. I joined Eversource Energy in 2019 as Director, System Planning. In 2024, I was named to my current position.

Q. Have you previously testified before PURA or elsewhere on regulatory matters?

A. Yes. I have provided comments and participation in technical sessions conducted by PURA in Docket No. 21-05-15RE02, PURA Investigation into Performance Mechanisms for a Performance-Based Regulation Framework, Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, Docket No. 17-12-03RE08, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards and Programs. I have also testified before the Federal Energy Regulatory Commission, the Massachusetts Department of Public Utilities, the Minnesota Public Utilities Commission, and the Michigan Public Service Commission.

Q. Mr. Horton, please state your name and business address.

A. My name is Douglas P. Horton. My business address is 107 Selden Street, Berlin, Connecticut.

Q. By whom are you employed and in what capacity?

A. I am the Senior Vice President, Regulatory and Strategic Financial Planning, for ESC. In this role, I am responsible for overseeing the development and monitoring of

Eversource Energy's operating year and long-range financial plan, and other related functions including investment planning, sales and load forecasting and corporate performance management. In addition, the teams that report to me are responsible for developing Eversource Energy's regulatory and rate-related filings before the jurisdictional regulatory agencies in Connecticut, Massachusetts and New Hampshire and the Federal Energy Regulatory Commission. My team is also responsible for the administration and oversight of Eversource Energy's investment-management decisions associated with approximately $12 billion in assets, including the employee pension and retirement plans and other trusts.

Q. Please summarize your education and professional experience.

A. I graduated from Bentley College (now Bentley University) in Waltham, Massachusetts in 2003 with a Bachelor of Science degree. In 2007, I graduated from Bentley University McCallum Graduate School of Business with a Master of Business Administration. I joined NSTAR Electric Company as a Senior Financial Planning Analyst in August 2007 and have taken on roles of increasing responsibility over time, culminating in my current role as Senior Vice President, Regulatory and Strategic Financial Planning, as of August 2025.

Q. Have you previously testified before PURA or elsewhere on regulatory matters?

A. Yes. I have testified numerous times in PURA proceedings on ratemaking and regulatory issues. I recently submitted testimony in Docket Nos. 24-03-30 and 25-12-

13. I have also testified on multiple occasions before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission.

Q. What is the Company requesting in this filing regarding a change to base rates and associated ratemaking proposals?

A. In this filing, the Company is requesting that PURA approve new delivery rates to alleviate a base revenue deficiency of approximately $451 million, before accounting for the impact of storm costs from 2018 to March 2025. The total revenue deficiency in the Rate Year, inclusive of the impact of the 2018 through March 2025 storms, is approximately $727 million. The Company's proposed base-rate change is based on a cost-of-service measured by a test-year ending December 31, 2025, adjusted for known and measurable changes through the rate year starting July 1, 2027.

For the reasons discussed in detail in this joint testimony, the Company is proposing that PURA approve a performance-based multi-year rate plan ("PBMRP"), covering a four-year term, July 1, 2027 through June 30, 2031, during which time the Company would be precluded from filing a general rate request under Conn. Gen. Stat. § 16-19. To support the implementation of the PBMRP, the Company is presenting a comprehensive 5-year targeted system performance ("TSP") plan with a budget plan, which the Company would plan to implement over the term of the PBMRP. The Company is also making other proposals, such as a request to establish a new mechanism for recovering storm costs to enable more systematic review and approval, while minimizing carrying costs.

Q. How has Eversource approached this case in terms of the future of electric service, affordability concerns and compliance with PURA's decisions on reliability and resiliency investment?

A. As stated above, the Company's filing is a request for a change in distribution rates, accompanied by the requisite documentation, analysis and compliance items arising since the Company's prior distribution rate proceeding in 2018. However, the Company is fully cognizant that its filing has significance well beyond the confines of PURA's docket proceeding. In Connecticut, Eversource provides essential electric service to 157 cities and towns across the State, covering over 85% of the State's geographic area. According to the U.S. Energy Information Administration ("EIA"), Connecticut is a state jurisdiction with some of the highest electric prices in the U.S. (third, only after Hawaii and California), experiencing an average retail price for electric supply of $24.37 per kilowatt-hour in 2024, as compared to the national average of $12.94.[1] Eversource has a critical responsibility to carry out its public-service obligations in a manner that deals effectively with the numerous challenges existing in the operating environment, including the need to achieve a level of "affordability" for customers, while at the same time ensuring that Connecticut residents and businesses have access to safe, reliable and resilient electric service that can promote a strong economy. CL&P's public-service obligation creates the imperative to balance these key objectives in a manner that is thoughtful, deliberate, and that steadily progresses toward a vision for the future state of the electric grid, while demonstrating leadership

[1] https://www.eia.gov/electricity/state/ (November 10, 2025).

on the energy policy issues that create costs for customers outside of the Company's distribution operations.

In this context, this case is about more than a change in distribution rates. With the benefit of a new, five-member commission invigorated to find genuine value for customers, while creating a stable and balanced regulatory environment, the Company understands that it needs to provide PURA with a firm vantage point into the Company as an institution, including its operating perspective and the way it is using its valuable human resources and critical information systems to serve customers reliably, efficiently and affordably. Consequently, the Company's filing in this case is structured to give PURA an in-depth view of the Company's operating platform, beyond the typical parameters of a distribution rate amendment. Without a clear understanding of where the CL&P system stands in relation to vital system-performance goals, it would be difficult for PURA to gauge the reasonableness of costs that customers will ultimately be asked to bear in relation to their electric service.

Therefore, the Company is presenting a holistic, detailed view of the distribution system and the plans that the Company has for maintaining and enhancing the performance of the system into the future, so that PURA has a clear line of sight into the impact of the decisions that it will ultimately make in this proceeding regarding cost recovery, a multi-year rate plan and other important issues. Eversource highly values its franchise in Connecticut and seeks to fulfill its important obligations to

electric customers and the broader State of Connecticut as a capable and productive partner. In this context, the Company recognizes that this case is important to establish credibility to that end.

Q. How do the various components of the Company's regulatory proposals in this proceeding work together to advance customer and public-policy objectives?

A. The Company's proposals are designed to form an integrated framework that strategically balance affordability, reliability, resilience, accountability and economic growth. Although each component of the Company's regulatory plan addresses a specific objective, together the Company's proposals drive a cohesive strategy that will address current customer needs and proactively prepare the electric system for the future.

The engine that drives the Company's plan is the 5-Year TSP, which is a comprehensive system-engineering plan that prioritizes proactive replacement of aging infrastructure. By addressing asset conditions before failures occur, the Company can enhance safety, reliability and resilience while optimizing the efficiency of system upgrades, reducing costly emergency repairs and minimizing customer outages.

Whereas the TSP acts as the engine driving the electric system forward, the PBMRP serves as the steering and control system, guiding direction and pace. The PBMRP limits spending growth with an inflation-based cap on O&M and a downward-only reconciling mechanism for capital investment costs, thereby incentivizing the Company to "stretch" for efficiency, while delivering greater rate stability and

predictability through a more gradual and transparent ratemaking framework than what would occur with sequential base rate cases. For accountability, the PBMRP proposal also incorporates a robust set of performance metrics that will serve as the gauges on the dashboard. These metrics are thoughtfully designed to provide insight into the Company's performance and demonstrate whether the plan's anticipated performance benefits are realized by customers. The Company has also proposed asymmetrical penalty and incentive structure for certain PIMs.

The Company's plan also incorporates a four-year stay-out commitment, providing greater certainty to customers by reducing the frequency of rate proceedings and establishing a stable regulatory framework for the Company to execute its plan. The stay-out provision presents a planned route that avoids unnecessary stops and detours.

Importantly, the Company's PBMRP allows customers to share in efficiency gains through a Consumer Dividend that increases as the Company achieves efficiencies under the plan, allowing customers to receive a direct share of the resulting savings.

The Company is also proposing heat pump and economic-development rates to advance state policy goals by promoting affordability and beneficial electrification, as well as stimulating economic growth by attracting and retaining businesses in Connecticut. These initiatives will help customers and communities realize the advantages of a modern electric system while reinforcing Connecticut's long-term energy and economic objectives.

Collectively, the Company's proposals chart a balanced and sustainable course that ensures safe and reliable service, strengthens system resiliency, improves operational efficiency, enhances rate predictability and stability, and creates value for customers, communities, and the State of Connecticut.

Q. What does all this mean for the Company's proposals in this case?

A. CL&P is a regulated electric company that cannot change its rates without the express approval of PURA pursuant to certain statutory requirements. CL&P provides essential electric service to customers on a cost-of-service basis and therefore must periodically return to PURA to request a realignment of its distribution rates to track its actual cost structure in order to remain on an operating course that fulfills the public-service obligations imposed by law. The added complexity is that there are customers on the other end of the equation that rely heavily on their electric service and, at the same time, may be challenged to pay for that service, regardless of the essential need. This complexity creates a persistent tension that gets placed into PURA's hands in a general distribution rate proceeding.

Accordingly, what the Company has strived to accomplish in this filing is to demonstrate that, although the concepts of "affordability," "reliability" and "resiliency" may be viewed by politicians and the general public as *competing priorities*, the concepts are – instead -- deeply intertwined. While maintaining a safe and reliable electric system requires adequate and consistent investment that *will add*

to customer bills, failing to make those investments imposes greater costs on customers over time due to declining reliability, the need to complete increasing emergency repairs that are more costly, and the materialization of operational inefficiencies and deteriorating conditions for electric infrastructure that jeopardize the ability of the Company to serve customers well. Where system investment is carefully planned and executed on the basis of operational expertise and data-driven analytics – and where utility management has instituted rigorous oversight controls for capital expenditures and operating expense – then, system investment will serve the *all-round* interests of customers over the long term, including affordability.

Accordingly, this proceeding is about more than establishing rates; it is an opportunity to coalesce around a shared vision for Connecticut's electric system and set a course for the next five years and beyond. The decisions made in this case will shape the state's electric infrastructure for the next decade and determine whether Connecticut is prepared for future economic, technological and societal demands. The proposals presented by the Company are designed to create a sustainable path forward that balances affordability with the investments needed to maintain and strengthen the electric system on which Connecticut depends.

Electricity powers homes, hospitals, schools, businesses, communications networks, transportation systems and, increasingly, the technologies that ultimately drive economic growth and quality of life. Expectations for reliability have never been

higher, and there is virtually zero tolerance for service interruptions, performance shortfalls, or infrastructure that cannot keep pace with evolving needs. Electricity is not just another service; it is foundational to the health, safety, welfare, and economic prosperity of Connecticut's residents and businesses. As a result, balancing affordability with necessary investments in safety, reliability, resilience, and future growth is the core focus of CL&P's proposals in this case. A reliable and resilient electric system requires disciplined planning, responsible execution, sustained investment, and a clear roadmap for the future. In this proceeding, the Company presents that roadmap to PURA for consideration, outlining the investments and ratemaking strategies needed to meet evolving customer expectations and future demand while ensuring safety, reliability and affordability.

Strong management oversight and internal accountability are important to this endeavor. Eversource recognizes that both PURA and the Company's electric customers expect investments to be carefully evaluated prior to the commitment of funds; for costs to be managed responsibly; and for resources to be directed toward projects with clear and measurable benefits to customers over the long term. CL&P's rate proposals incorporate this accountability and provide assurance that customer dollars will support projects that deliver measurable value to customers.

Fulfilling the public-service obligations imposed by law requires access to capital because developing the infrastructure necessary to operate, maintain and modernize the

electric system is a substantial undertaking and the assets are long-lived. Customer rates do not yield sufficient revenue on a day-to-day basis to fund this undertaking and Eversource must therefore depend on investors and lenders for the capital to build, maintain and improve the system. In turn, these stakeholders must have confidence that prudent investments will be made and that the regulatory framework will support recovery of invested dollars, as is necessary to maintain access to capital at reasonable cost. Financial strength is not an end in itself; in fact, it is essential to maintaining the safe, reliable and resilient electric system customers expect and deserve.

Meeting the challenges of a modern electric system will also require ongoing innovation. Eversource firmly recognizes that it must continually identify smarter and more efficient ways to operate, invest and serve its customers. The proposals presented to PURA in this filing reflect that commitment, advancing innovative approaches designed to improve reliability, strengthen resilience, support future growth and deliver greater value for customers.

Q. What is the institutional culture that Eversource strives to build among its employees?

A. As an institution engaged in the delivery of essential services to valued customers, Eversource's internal culture emphasizes responsibility, dedication, quality of effort and a "customer-first" mindset. The Company's customers are its highest priority and employees are its greatest asset, providing the experience, expertise and professionalism needed to operate and maintain Connecticut's critical electric

infrastructure for the benefit of customers. Eversource is committed to achieving a balance of reliability, resiliency and affordability, while advancing innovative solutions that improve performance and efficiency.

Above all of this, PURA has a central role in shaping the future for electric customers because it will make decisions in this case that will directly influence the delivery of power to customers for the foreseeable future. CL&P stands ready to be accountable for results; to improve performance and efficiency on a consistent basis; and to work collaboratively with PURA and other parties to chart a sustainable path forward that serves customers' interests.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present the Company's proposals for maintaining an electric distribution system that is safe, reliable, resilient and affordable, including discussion on the following matters: (1) the factors affecting electric affordability and a framework for evaluating and addressing affordability; (2) the Company's operations and ongoing efforts to improve performance, reliability, efficiency and customer service; (3) CL&P's proposed five-year targeted system performance ("TSP") plan and how it balances reliability, resilience, safety and affordability; (4) the Company's proposed performance-based multi-year rate plan (the "PBMRP"); and (5) the Company's proposals for the recovery of storm costs. In combination, these proposals

are designed to align regulatory objectives with incentives for efficiency and customer value.

This testimony provides the roadmap and context for the Company's proposals and explains how those proposals work together to deliver the service customers expect today, while preparing the electric system to meet the needs of tomorrow. The specific elements, details and supporting analyses underlying the Company's ratemaking proposals are presented in the testimonies of other witnesses accompanying this filing, as specifically identified below, in Section VIII of this testimony.

Q. Are you presenting any exhibits as part of your testimony?

A. Yes. We are presenting the following exhibits with our testimony:

Exhibit	Description
Exhibit CLP-ELP-1	Joint Direct Testimony of Donald J. Scacco, Jr., Digaunto Chatterjee and Douglas P. Horton
Exhibit CLP-ELP-2	S&P Ratings Action (Dec. 9, 2024); Moody's Ratings Action (Jun. 24, 2025).
Exhibit-CLP-ELP-3	Performance Metric Summary Table
Exhibit-CLP-ELP-4	Management Audit of Eversource Energy's Connecticut Companies, February 11, 2025

Q. How is your testimony organized?

A. Our joint testimony is organized into the following sections.

- Section I is the introduction.
- Section II examines the factors that impact electricity affordability and presents a framework for assessing affordability challenges.

- Section III provides an overview of the Company's operations and discusses efforts to improve operational performance, efficiency and customer service.

- Section IV outlines the Company's proposed 5-year Targeted System Performance ("TSP") plan and discusses how it integrates safety and reliability, innovation, effective management oversight and accountability and a roadmap for future development.

- Section V outlines the Company's proposed Performance-Based Multi-Year Rate Plan ("PBMRP") and its role in supporting regulatory objectives of efficiency, affordability and customer value.

- Section VI discusses a new ratemaking approach for storm cost recovery that is designed to mitigate customer rate volatility, better align cost recovery with underlying service costs, reduces customer exposure to carrying charges and enables more timely cost recovery.

- Section VII synthesizes the Company's proposals and explains how they advance PURA's regulatory objectives, support the state's policy goals, and promote a more efficient and affordable electric system.

- Section VIII introduces the Company's witnesses and the accompanying testimony supporting the Company's proposals in this proceeding.

- Section IX is the conclusion.

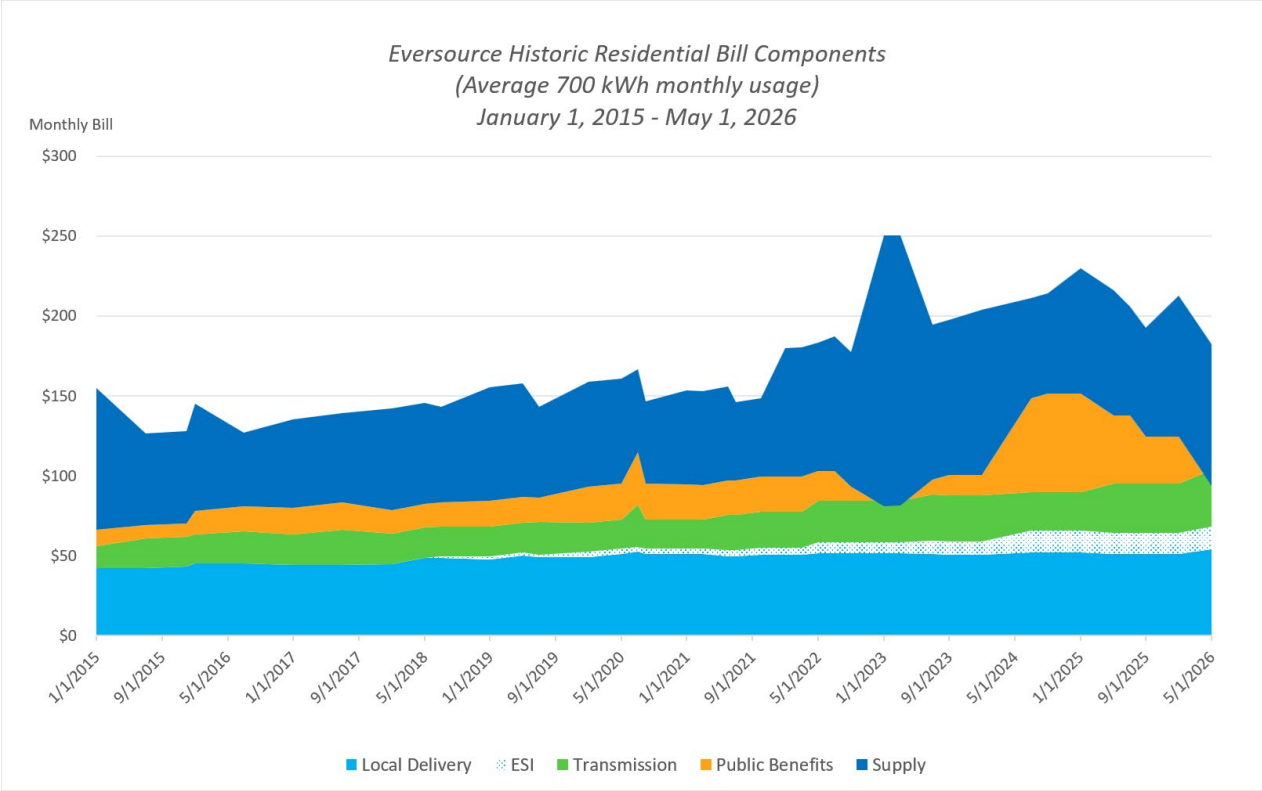
II. <u>The Affordability Challenge</u>.

Q. What are the factors that Eversource views as the primary contributors to Connecticut's relatively high electric prices?

A. Residents in Connecticut are experiencing financial challenges and frustration related to several essential services, including housing, fuel sources, healthcare and the overall tax burden. With respect to essential electric service, customer bills incorporate four categories of charges: (1) energy supply; (2) transmission; (3) public benefits; and (4) distribution, including the currently effective Electric System Improvements

("ESI") charge. Among these factors, energy supply is the greatest challenge to residential affordability, as is demonstrated in Figure 1, below.

Figure 1: Customer Bill Components, 2015 to 2026



Q. What portion of a CL&P customer bill is associated with energy supply and what are the reasons that energy supply poses a tough challenge for Connecticut electric customers?

A. On the CL&P customer bill, supply charges reflect the cost of electricity purchased through the regional, competitive ISO New England ("ISO-NE") market from third-party generators that produce power at electric generating facilities. CL&P does not currently own any generation assets. Instead, the costs incurred by CL&P on behalf of

customers as a result of wholesale market procurements are passed directly through to customers, with no profit to the Company.

As shown in Figure 1, above, supply charges are the largest and most volatile component of a customer's electric bill. In addition to wholesale electricity costs, supply rates include the costs required to comply with state environmental mandates. Specifically, supply-related costs reflect expenses associated with the Regional Greenhouse Gas Initiative, which is intended to reduce carbon dioxide emissions from the electric power sector.

Importantly, high electricity supply costs are not unique to Connecticut—these prices reflect broader regional conditions. The six New England states consistently have some of the highest electricity prices in the nation. There are multiple factors driving these elevated costs; most notably, the "scarcity" of natural gas for electricity generation, particularly during the winter peak period. The ISO-NE External Market Monitor has expressed concerns about the composition of the future generation fleet that would further affect supply affordability. As shown in the figure below, virtually none of the generation projects in the ISO-NE interconnection queue are dispatchable conventional resources.

Figure 2: Active Projects in the Interconnection Queue[2]

Technology	# Projects	GW	% of GWs
Solar*	228	4.9	12%
Battery Storage	122	18.4	45%
Land Based Wind	15	2.7	7%
Offshore Wind (Active Contract)	2	1.5	4%
Offshore Wind (No Contract)	19	11.9	29%
HVDC	1	1.2	3%
Fossil	6	0.1	0%

* Includes 94 hybrid solar projects (incl. storage) totaling 1.4 GW

As explained by the Market Monitor, battery storage accounts for a significant share of the interconnection queue; however, these resources are quite limited in their ability to meet wholesale market reliability needs.[3] Therefore, "[i]t will be critical to retain a large share of the existing dispatchable generation and avoid mandating retirements of fossil fuel resources[.]".[4]

Q. In Eversource's opinion, what could be done to reduce the cost of energy supply in Connecticut?

A. Eversource Energy has long understood that bringing additional baseload generation to market is an imperative to reduce energy supply costs for electric customers. We have already seen the increased price effects of diminishing baseload generation from the retirement of 3 GW over the past five years. There are no two ways about it – and, in

[2] Potomac Economics (External Market Monitor for ISO-NE), 2024 Assessment of the ISO New England Electricity Markets, p. 19 (June 2025).

[3] Potomac Economics (External Market Monitor for ISO-NE), 2024 Assessment of the ISO New England Electricity Markets, p. 19 (June 2025).

[4] Id.

the past 15 years, Eversource Energy has been a proponent in three major generation-related projects, including the proposed development of hydropower from Canada, the proposed development of interstate gas transportation to support electric generation, and offshore wind generation – all of which were challenged through applicable regulatory channels. Only offshore wind generation is progressing to commercial operation following project divestiture by Eversource Energy. Still, there is growing recognition among New England policymakers that affordability concerns cannot be assuaged without considering changes that would loosen New England's natural gas infrastructure constraints, given that other alternatives are not coming to fruition as quickly as hoped. For example, in Connecticut, Governor Lamont has expressed support for expanding natural gas pipeline capacity into New England to lower energy costs, which Eversource views as a positive development.

In fact, Connecticut has a track record of taking steps to protect the interests of Connecticut customers, at least in relation to electric supply. Allowing regulated utility companies to own a limited amount of electric generation capacity, such as that associated with a peaking facility, would be a singular step forward in addressing the affordability conundrum for Connecticut customers. Enabling utility ownership of generation (particularly peaking generation), as Connecticut has done in the past, would help to improve affordability by increasing regional electric supply and putting downward pressure on electricity prices. As discussed above, commodity prices are driven in large part by the imbalance existing between supply and demand in the ISO-

NE market. Adding bulk generation, even just during peak periods, would help reduce scarcity conditions that lead to higher wholesale prices and price volatility. Unlike merchant developers, regulated utilities like Eversource often have lower costs of capital, longer-term planning horizons, and an obligation to serve customers, enabling them to develop resources that might not otherwise get built due to financing challenges or other barriers.

Q. What are the Company's thoughts on whether progression from today's resource mix to a future with utility-owned generation is needed?

A. Optimal outcomes are realized when all stakeholders share a coordinated, consensus-driven vision for the state's incremental supply needs and the timing for meeting them. A shared vision would enable meaningful reductions in regional energy prices while effectively addressing resource adequacy challenges.

To that end, an initial step would be to launch a Comprehensive Independent Integrated Resource Plan ("CIIRP") stakeholder process. This process would need to be unbiased and holistic, thoroughly evaluating all potential supply options, the associated costs and implementation challenges, without preference for any particular energy source or demand-side approach. The result should be a specific plan that remains relevant across a range of future economic scenarios and that can serve as the guiding framework for all future generation buildout decisions. The CIIRP should be updated every five years, striking a balance between stability in procurement decisions and adaptability to prevailing economic conditions.

Incumbent Transmission Owners should play an active role in the process, contributing not only as participants but also by providing detailed transmission planning analyses. These analyses should include specific interconnection costs for various generation types and locations on the transmission grid, with the goal of minimizing transmission infrastructure upgrade expenses. This approach would apply to both optimal siting and right-sizing Battery Storage and Gas Generation. Similarly, incumbent gas utilities should be engaged in the process by conducting analyses to determine the most advantageous locations on the gas pipeline network for future gas generation. By right-sizing generation, they can help minimize the need for gas infrastructure upgrades and reduce projected gas prices.

Lastly, as part of the CIIRP, it would be essential to assess whether the current wholesale market design and price formation mechanisms provide sufficient signals to support investments in new battery storage, gas generation, and the corresponding transmission and gas infrastructure. Both sectors face a classic chicken-and-egg dilemma, which is: should infrastructure be built first in anticipation of generation, or should generation lead, prompting infrastructure upgrades? If it is determined that building transmission and gas infrastructure would indeed spur generation development, incumbent transmission and gas utilities should be required to construct the necessary upgrades, with cost recovery through established regulatory mechanisms.

If, after these infrastructure upgrades, the wholesale market price signals remain inadequate to incentivize the timely development of the new generation needed to meet planning reserve margins, a further step would be required. Specifically, the minimum generation buildout needed to satisfy ISO-NE reserve requirements, as identified in the NERC Long-Term Resource Assessment, should be determined. This amount should be sufficient to avoid reliance on operating reserves or, in worst case scenarios, load shedding, thereby maintaining grid safety and reliability. Procurement for this generation should be open to all qualified parties, including regulated utilities, through a competitive bidding process with a pre-set authorized return on equity. This approach would ensure that sufficient supply is built to meet reliability standards in the most cost-effective manner possible.

Q. Is the Company doing anything to bring this option forward for consideration in the legislature?

A. Yes, the Company is currently evaluating certain resource options that could be developed in Connecticut so long as support for the projects under Connecticut law could be obtained for project development. For example, there may be an opportunity to coordinate upgrades to the gas distribution and transmission systems to increase firm gas supply in southeast Connecticut, facilitating either the buildout of a new natural gas combined-cycle generation unit or firming up an equivalent amount of gas supply for existing generation. These project options would address the looming Resource Adequacy deficiency in New England, while ensuring rate suppression despite

diminishing supply to meet summer and winter peak electric demand. More immediately, it would address the over-reliance on oil generation during winter peak periods. The Company anticipates that the upcoming legislative session may present an opportunity to consider generation alternatives.

Q. What portion of a customer's bill is attributed to transmission and what are the main factors driving these costs?

A. Electric transmission charges cover the costs of New England's regional high-voltage transmission system, which moves electricity from generating facilities to local distribution networks serving customers statewide. These charges fund the development, operation and maintenance of transmission infrastructure, including lines, substations and related equipment. Without adequate bulk generation, the transmission system has become a vital linchpin in maintaining the integrity of the New England bulk power grid and customers have benefited greatly from the substantial investment that has occurred over the past 20 years.

Transmission rates are set by the Federal Energy Regulatory Commission ("FERC"), which oversees interstate electric transmission. Since New England's electric grid operates as an integrated inter-state regional system, transmission costs are shared across the region and subject to federal review and approval. Electric distribution companies ("EDCs") do not determine transmission rates; instead, the EDCs recover FERC-approved transmission costs through customer bills. Transmission charges currently make up a relatively small portion of the total electric bill, i.e., roughly 4.4

cents per kilowatt-hour across all customers, despite the fact that regional transmission investments have steadily increased to maintain system reliability, strengthen grid resilience and meet evolving energy needs. ISO-NE reports that over $13 billion has been invested in transmission infrastructure from 2002 to 2025, without causing material bill impacts for customers due to the long-term nature of investment recovery.[5] These costs will be proportionally allocated to Connecticut and stand as a critical bill component helping to stabilize the energy delivery system in New England.

Q. What portion of a customer's bill is associated with public benefits, and what are the primary drivers of the costs comprising the "public benefits" charge?

A. The Public Benefits Charge is a state-mandated fee structure that consists of three separate charges: (1) the Renewable Energy Investment Charge; (2) the Conservation and Load Management Charge; and (3) the Systems Benefit Charge.

The Public Benefits Charge funds programs and initiatives established by the Connecticut Legislature. These include customer assistance for qualifying households, energy efficiency programs, renewable and carbon-free energy procurement, and incentives for solar generation and electric vehicle adoption. As shown in Figure 1, above, the Public Benefits Charge constituted a relatively large portion of a typical electric bill between 2023 and 2026. Unlike electric supply charges, most costs collected through this charge are not directly linked to an individual customer's

[5] ISO-NE, About Us, Key Grid and Market Stats, Transmission, https://www.iso-ne.com/about/key-stats/transmission.

electricity usage or customer class, constituting a source of frustration for electric customers. Rather, these costs reflect statewide policy mandates set by legislation.

Figure 1, above, shows that the Public Benefits Charge has fluctuated significantly over the past three years. A major factor has been the EDCs' mandated long-term contract with the Millstone Power Station. Connecticut's electric distribution companies are required to purchase electricity from Millstone at a fixed contract price and resell it into the ISO-NE market. When wholesale prices are higher than the contract price, customers benefit from savings. Alternatively, when wholesale prices fall below the contract price, customers face added costs.

More recently, funding for certain items in the Public Benefits Charge changed as a result of the passage of Public Act 25-173. This legislation authorizes up to $250 million ($125 million in Fiscal Years ("FY") 2026 and 2027)[6] in state bonds to fund hardship protection programs, and up to $50 million in bonds ($30 million in FY 2026 and $20 million in FY 2027) to support electric vehicle charging initiatives. By using bonds rather than electric rates to finance these programs, the law shifts certain costs away from customers' utility bills. The Act also lowered the state's Class I Renewable Portfolio Standard target, further reducing the Public Benefits Charge.

[6] FY 2026 runs from July 1, 2025 to June 30, 2026 and FY 2027 runs from July 1, 2026 to June 30, 2027.

Q. Do public benefits charges have an impact on economic development in Connecticut and thereby on affordability?

A. Yes. Although the programs supported by the public benefits portion of a customer's bill do provide benefits, these charges are recovered through electric rates on a volumetric basis, naturally driving up electric-input costs for Commercial and Industrial customers. Relatively higher electric prices cause these important contributors to Connecticut's economy to be less competitive relative to their peers in other states where similar costs are not levied through electric rates. This competitive disadvantage has the strong potential to depress business creation and expansion in Connecticut. By impairing the ability of businesses to increase load and stifling the creation of new commercial customers, more of the cost must be shouldered by residential customers, contributing to affordability concerns for critical energy service in a state with some of the highest electric rates in the country.

Q. Are customers voicing concerns about the public-benefits programs they pay for on their electric bills?

A. Yes. Customer sentiments that directly refer to public-benefits charges represent approximately one-third of the total sentiments expressed by customers about their energy costs and that portion of customer feedback reached as high as 53% during the hottest summer months when customers typically experience the highest electric bills of the year. Although customers highly value the transparency of the newly redesigned electric bill -- it has created customer reactions. For example, some of the customer feedback received by the Company is as follows:

"...Not happy to see a public charge but if we have been paying that all along then at least its transparency. That shouldn't come from our electric bill though since we pay so much in taxes..."

Q. Does the Company support a customer-impact analysis on Connecticut's public benefits programs?

A. Yes, fully. Together with key stakeholders, it is important to consider ways to reduce costs paid for by our customers on their electric bills. The Company looks forward to meaningfully engaging in the evaluation directed by PA 25-173, which OCC is designated to lead. The "purpose, costs and benefits associated" with combined public benefits charges will be assessed and reported to the legislature by October 1, 2026. This assessment will also fulfill objectives of Conn. Gen. Stat. § 2-24a(b), which requires assessment of whether energy legislation will "significant direct financial impact on the cost of electricity to the majority of Connecticut electric ratepayers." Costs for public benefit programs represented approximately 21% of the average residential customer bill in 2025 and assessing these charges is an important part of the affordability solution framework to ensure that customers are receiving value for the public-benefits programs they are paying for on their electric bills.

Q. What more can be done to reduce public benefits charges in Connecticut?

A. Because the Public Benefits Charge is mainly a creature of statutory mandates, any meaningful reduction would require policymakers to reconsider either the programs funded by the charge or how they are financed. In other words, lasting reductions in

these costs depend primarily on legislative action, although the Company would support an effort by PURA to conduct an intensive, holistic review of the charges encompassed within the Public Benefits Charge to determine whether changes could or should be recommended to the General Assembly.

Q. What portion of a customer's bill is associated with distribution service, and what are the primary drivers of distribution cost?

A. Distribution service has constituted a range of 19 to 30 percent of the total customer bill over the past five years and currently accounts for approximately 25 percent of the total bill. With the impact of the Electric System Infrastructure charge included, this figure has averaged 31 percent. The electric distribution charge covers the costs of building, owning, operating and maintaining Connecticut's electric distribution system, which delivers electricity to customers statewide. This distribution system encompasses poles, wires, substations, meters, transformers, and other infrastructure needed to provide safe, reliable and resilient electric service. Because these projects provide long-term benefits, their costs are recovered gradually, incorporated into rate base and repaid over time through depreciation and a return on investment authorized by PURA. Capital investments are the only component of distribution rates on which the Company is permitted to earn a return. Unlike routine operating expenses, infrastructure projects require utilities to obtain financing from investors and lenders before those costs can be recovered from customers.

Q. How does the Company finance these distribution assets?

A. The Company finances these distribution assets through a combination of debt and equity capital raised in the financial markets. Debt investors provide capital with the expectation of regular interest payments and eventual repayment of principal. Equity investors, on the other hand, seek returns through dividends and long-term share price appreciation but assume greater risk than bond holders, as they have no contractual guarantees and are subordinate to debt holders in the event of bankruptcy. Accordingly, debt carries lower risk and requires a lower return, while equity demands a higher expected return to compensate for its higher risk.

The authorized return is not a guarantee but is intended to compensate capital providers and allow CL&P to maintain continued access to the financing necessary to sustain and modernize the electric system. Customers repay these investments over the useful lives of the assets—often several decades—which aligns cost recovery with the period during which customers receive the benefits of the infrastructure.

Q. Do bond credit ratings actually influence the cost of financing distribution assets?

A. Yes. Credit ratings significantly influence a utility's cost of debt. Utilities with strong credit ratings can secure loans at lower interest rates, while those with weaker ratings pay higher rates. Consequently, a decline in credit quality raises financing costs for infrastructure investments, which ultimately increases the overall cost of providing service to customers.

Q. Have major credit-rating agencies commented on Connecticut's regulatory environment?

A. Yes. The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's ("S&P") Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. On December 9, 2024, S&P downgraded CL&P's credit rating by one notch, citing increased business risk for Eversource Energy and its Connecticut subsidiaries. S&P highlighted concerns following the Connecticut Natural Gas and Southern Connecticut Gas Co final rate-case orders, resulting in material base-rate decreases for both utilities and coming after a pattern of several years of adverse regulatory developments for investor-owned utilities operating in Connecticut. S&P also reflected concern about a pattern in Connecticut of below-average returns on equity ("ROE"), regulatory lag, and inconsistent achievement of authorized ROEs and credit-supportive regulatory outcomes (Exh. CLP-ELP-2, p. 2). Subsequently, on June 24, 2025, Moody's downgraded CL&P's credit rating, citing challenges in Connecticut's regulatory environment, including unpredictable regulatory decisions and rate-case outcomes (Exh. CLP-ELP-2, pp. 21-22) resulting in significant volatility in CL&P's financial profile. These downgrades have increased the cost of long-term debt for the Company and its customers. On a positive note, recognizing recent changes in the Connecticut regulatory environment, Moody's recently changed Eversource Energy's bond rating outlook from negative to stable on July 6, 2026, due to increased financial flexibility following the PURA draft decision on Connecticut storms on June 29, 2026, and the closing of the Aquarion sale on June 30, 2026.

Continued improvement in the regulatory environment should have a positive impact on this measure.

Q. What other factors influence distribution costs?

A. In addition to the recovery of the revenue requirement associated with capital projects, distribution rates are designed to provide a level of recovery for the day-to-day expenses required to operate and maintain the electric system. These include employee wages and benefits, materials and supplies, fleet and equipment costs, customer service and billing, and payroll and property taxes. Together, these expenditures are essential to ensuring the ongoing operation of a safe, reliable, and resilient distribution network. However, all of these costs are subject to market forces and inflation. As a result, the management of these costs receives close attention from Eversource's management team.

Q. What does Eversource view as a pathway to control the rate of cost increases in distribution rates?

A. There are limited opportunities to materially reduce the cost of core distribution service because, fundamentally, the revenue requirement included in base rates is tied to the physical assets required for safe and reliable electric service and the ongoing need to maintain reliability, replace aging equipment, meet regulatory requirements, and respond to increasingly severe weather, meaning that the costs of investment and day-to-day operation cannot simply be eliminated or even materially reduced. At the same time, all of these costs are susceptible to inflation and other economic pressures, driving

prices upward. As a result, the greatest opportunity for cost containment is efficient operations and investment. To that end, Eversource's experience is that operational efficiency is promoted under a multi-year ratemaking approach, such as performance-based ratemaking, which encompasses a multi-year "stay-out" period. When utilities have sufficient revenue support to focus intently on operations rather than on preparing and litigating rate cases – and has made a commitment to forego filing a rate case to solve financial needs – there is a high likelihood that the utility will push to maintain cost efficiency during the stay out, creating permanent, long-term efficiency gains for customers.

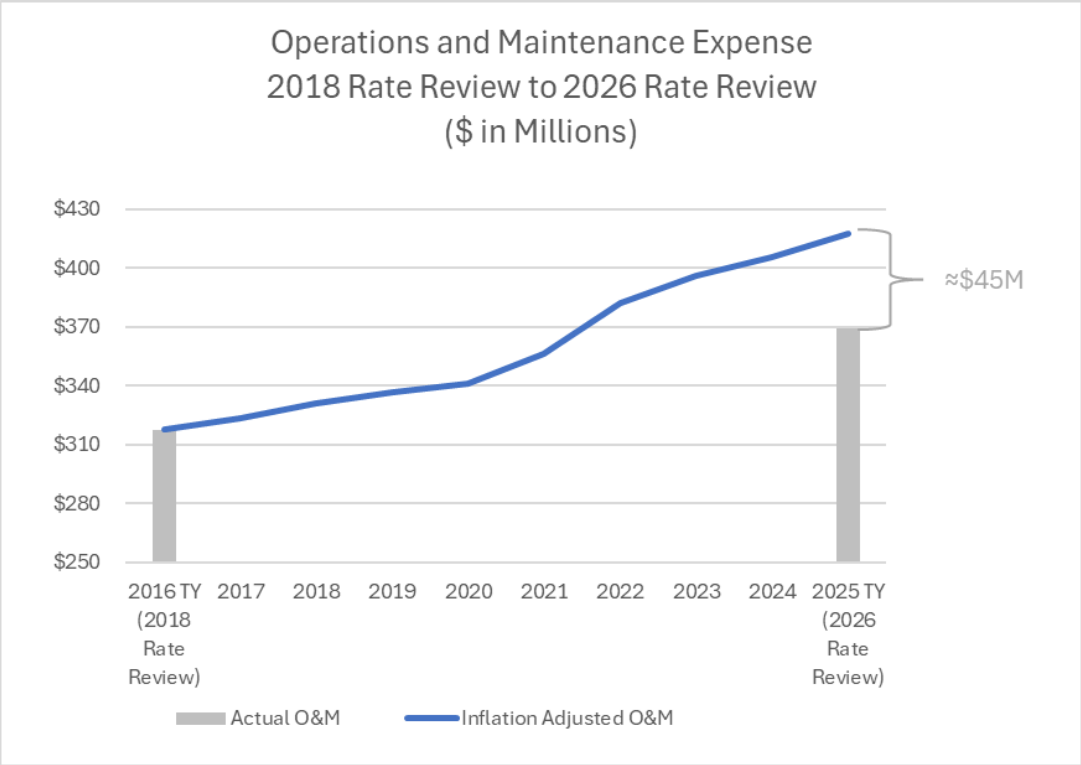
Q. What is a good example of this experience?

A. Since PURA's prior rate review in the 2018 rate case, Docket No. 17-10-46 (April 18, 2028), the Company has worked diligently to contain operating and maintenance ("O&M") expense by deploying rigorous budgetary and procurement controls across all operating functions, in addition to using other strategies to achieve operational efficiencies everywhere possible. This hard work paid off for customers with tangible impacts. Specifically, inflation in the general economy, as measured by the Gross Domestic Product Price Index ("GDP-PI"), trended at approximately 30% over the period 2016 through 2025.[7] By comparison, the Company's O&M expense level increased by approximately

[7] Source: U.S. Bureau of Economic Analysis; Moody's Analytics Forecast.

16 percent over the same time frame, saving customers an estimated $45 million annually, as compared to aggregate inflation trends. This dynamic is shown in Figure 3, below.

Figure 3: Operations & Maintenance Expense Trends



Q. Does consistent investment in the electric distribution system also generate benefits for customers in terms of reducing overall, long-term operating cost?

A. Yes. The most cost-effective approach to maintaining steady utility rates is to invest on a proactive and consistent basis, replacing aging equipment in a timely manner and to leverage data-driven predictive planning models that identify the most cost-effective

upgrade for a given line segment or substation equipment. Conversely, the most cost-*ineffective* approach is to under-invest in the system – driving the system toward high failure rates and toward a poor safety and reliability environment – a situation where replacement rates have fallen dramatically behind failure rates – then reacting to it by playing catch-up by taking on the replacement of aging assets in poor condition in a hurry.

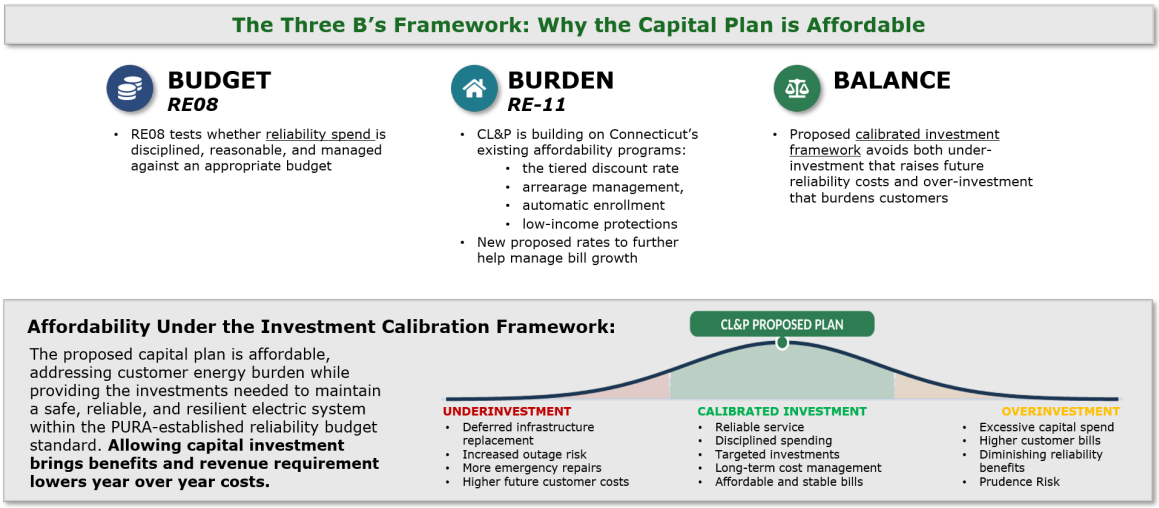
Where a utility system is not maintained in good condition, the *expense* of operating that system increases over time because the utility will be compelled to employ myriad strategies to address emergent issues at a higher cost than would occur with more proactive investment, displacing the probability of system failure. In that regard, it is widely recognized that proactive distribution system improvements by electric distribution companies reduce the frequency and duration of interruptions for residential and commercial customers – and the attendant costs. A proactive asset replacement strategy not only addresses poor reliability, aging infrastructure and current loading conditions but also adds new capacity to the distribution system to support the load growth that Connecticut seeks as a matter of economic development. Customers will always be better off with consistently adequate and stable investment levels over time both in terms of service and cost experience.

Q. How is Eversource addressing the challenge of affordability in this case?

A. Over the past year, Eversource has devoted considerable effort to developing an internal framework to guide its consideration of affordability issues, as it plans and operates the distribution system. In this regard, "affordability" cannot mean that any rate change is unacceptable or inappropriate for customers because customers need electric distribution service for their health, safety and convenience and that service comes at an (increasing) cost. Instead, Eversource sees the challenge of "affordability" as requiring a mindset of vigilant efficiency, rigorous processes for cost control and the calibration of investment to maximize long-term customer value at the lowest reasonable cost, while managing near-term bill impacts. This affordability perspective supports implementing structured ratemaking mechanisms, such as the Company's proposed performance-based multi-year ratemaking plan, which is designed to enable targeted, disciplined investment while holding the Company accountable for delivering appropriate service levels and measurable benefits, as discussed in this testimony.

To promote a discussion of "affordability" concepts in this docket, the Company has prepared testimony from two witness panels, including the principals of Apex Analytics LLC ("Apex") and the Company's internal customer experts. Apex has developed an integrated framework for evaluating the affordability of the Company's planned distribution spending and investments. As shown in the figure below, this framework is structured around the "Three Bs," which are Budget, Burden and Balance, drawing on foundational frameworks developed by PURA over the past few years.

Figure 4: Affordability Framework[8]



As discussed in the Apex testimony, the "Budget" lens represents the Company's financial perspective and examines whether the Company's capital plan is disciplined, expenditures are reasonable and well justified, and investments are managed within an appropriate budgeting framework. The "Burden" lens represents the customer perspective and focuses on whether customer bills remain manageable and costs are allocated equitably across households. The "Balance" lens reflects PURA's perspective and assesses whether the pace and scale of investment are appropriate, aiming to avoid both overinvestment (which can increase costs without commensurate benefits) and underinvestment (which can erode reliability, create future cost pressures, and ultimately harm customers). Taken together, these perspectives offer a practical

[8] Under "Budget", "RE08" refers to Docket No. 17-12-03RE08. Under "Burden", "RE11" refers to Docket No. 17-12-03RE11.

framework for assessing affordability, recognizing both the long-term value delivered to customers and the near-term bill impacts.

III. Overview of the Eversource System.

Q. Please briefly summarize Eversource Energy's organizational structure and CL&P's place within it.

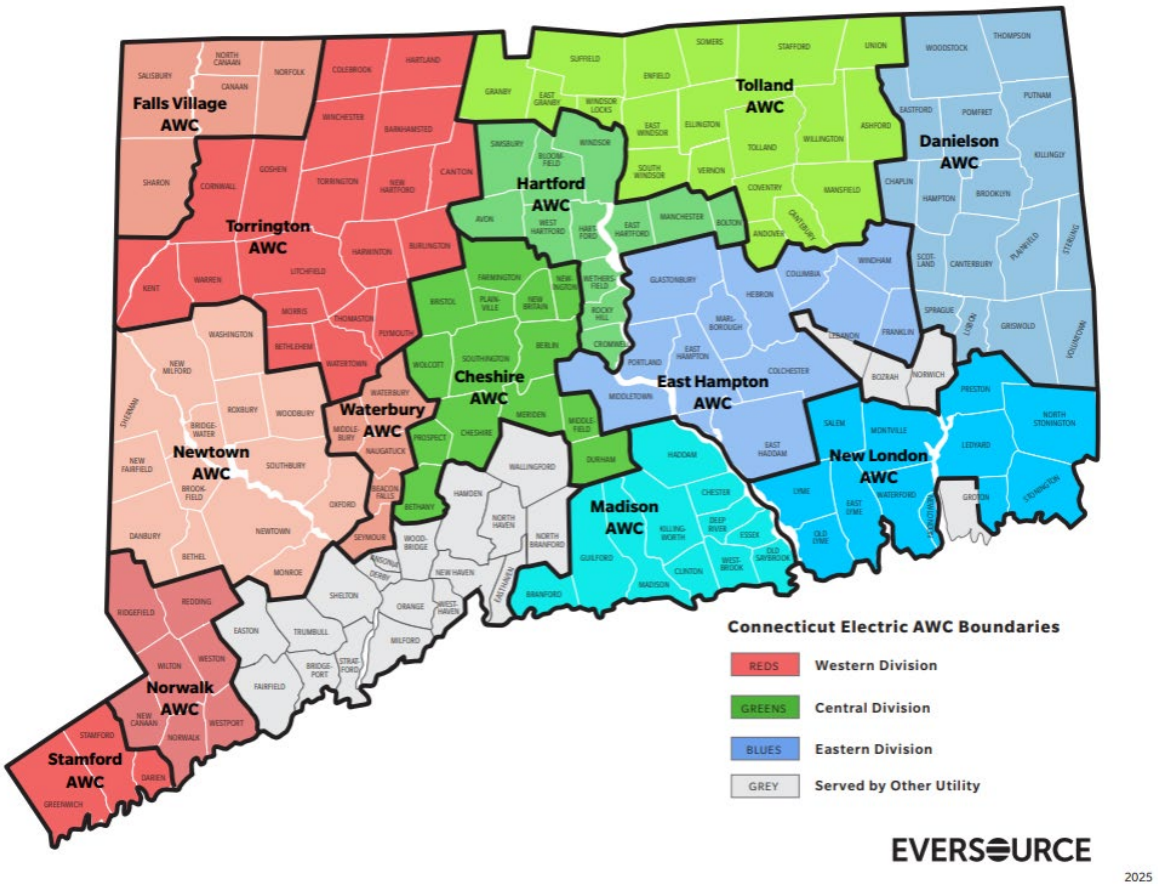
A. Eversource Energy is a Fortune 500, publicly traded utility holding company headquartered in Boston, Massachusetts and in Hartford, Connecticut, and serving approximately 4.6 million customers in Connecticut, Massachusetts and New Hampshire. Eversource Energy's wholly owned regulated subsidiaries include CL&P, NSTAR Electric Company, Public Service Company of New Hampshire; Yankee Gas, NSTAR Gas and Eversource Gas Company of Massachusetts.

CL&P's President, Donald Scacco, reports directly to Eversource's Chief Operating Officer, Paul Chodak, who is part of the Senior Executive Team and reports directly to the Chief Executive Officer. Mr. Scacco is responsible for developing CL&P's capital and O&M plans, meeting performance targets, leading project initiatives, overseeing the annual O&M budget, ensuring employee safety, managing external affairs, building stakeholder relationships and overall business operations.

Q. Please provide an overview of CL&P's operations.

CL&P's service area covers 4,400 square miles or 87 percent of Connecticut's total geographic area.

Figure 5: Service Territory Map



CL&P's service territory encompasses 157 communities, including major urban centers such as Hartford, Stamford, and Waterbury, as well as surrounding suburban and rural

areas. As of December 31, 2025, CL&P provided retail electric service to approximately 1.3 million customers.

CL&P's electric transmission system includes approximately 1,684 circuit miles of overhead transmission lines and 143.7 miles of underground transmission. The Company operates 22 transmission substations, 99 bulk distribution substations supplied by its transmission system, and 57 non-bulk distribution substations supplied by its distribution system.

CL&P's distribution system consists of approximately 16,700 circuit miles of overhead primary lines and 7,000 circuit miles of underground primary lines, including both direct-buried and underground duct/manhole construction. Primary distribution voltages range from 4.8 kV to 34.5 kV, with most circuits operating at 4.8 kV, 13 kV, and 23 kV. The Company uses approximately 265,000 distribution service transformers to supply its customers.

CL&P's service territory is divided into three operating divisions, with 12 Area Work Centers ("AWCs") and one Electric Field Organization ("EFO") satellite work center.

OPERATING DIVISIONS AND AREA WORK CENTERS
• Central (Cheshire, Hartford, Tolland) • Eastern (Danielson, East Hampton, Madison, New London) • Western (Newtown, Norwalk, Stamford, Torrington, Waterbury)

Q. Please provide an overview of the current state of the CL&P electric distribution system and the key characteristics that are relevant to reliability and operational performance.

A. Despite years of consistent investment to maintain and replace aging overhead assets, a significant portion of the overhead system is comprised of legacy bare-wire copper conductors. A large proportion of the in-service bare copper conductors are beyond their 40-to-50-year service life and have degraded due to "annealing," which reduces the tensile strength of the conductor and metal fatigue, leading to failures at connectors, insulators and splices. Without protective coverings, these conductors are vulnerable to contact from tree limbs or other vegetation, which can instantly interrupt service and cause customer outages during blue-sky, grey-sky and storm conditions.

The distribution system also contains a significant portion of 4.8 kV infrastructure. This older, lower-voltage design is less efficient and increasingly unable to meet modern power needs and requires conversion to the predominant primary distribution system voltage in the area.

Many of the distribution system's supporting assets are nearing or have surpassed their useful lives. By 2031, a large percentage of the Company's bulk transformers will be over 50 years old. Although asset age is not a direct indicator of asset health, older transformers are more likely to fail. Most of the wood-pole fleet comprises legacy poles that fail to meet current strength standards, while key equipment—such as

switchgear, load tap changer controls, and electromechanical relays—is becoming obsolete and requires expedited replacement to reduce the risk of failure.

Q. How does CL&P operate the system from day-to-day to maintain safe and reliable service to customers, despite the system's aging condition?

A. Eversource Systems Operations has ownership, overall responsibility, and authority for the safe, reliable and efficient operation of the CL&P distribution and transmission system and acts to maintain or restore the distribution and transmission system to a safe and reliable condition, when contingencies occur.

The System Operator directs field personnel, primarily Response Specialists, to respond to Priority 1 events and to safely restore customers as soon as possible when outages occur. Once safe conditions are established in the field, an evaluation and judgment must be performed to determine the sequence of restoration work. Restoration work may include opening taps, cutting phase wires, or temporary repair work to restore the greatest number of customers and avoid lengthy outages.

The SOC is critical to the transmission and distribution electrical systems and is the central coordinating agency for all transmission and distribution systems. Accordingly, activities conducted within the control room environment are limited to essential processes for supporting the transmission and distribution system operations only. Operating platforms (OMS, SCADA) and other applications are closely monitored and prompt action is taken to investigate and correct abnormalities. Generally, SOC access

is limited to individuals on official business to ensure that operators are not distracted from their duties.

The System Operators and System Operator Supervisors and Managers have operational knowledge of the electrical system to be controlled and are responsible for all aspects of system operations and for the coordination of emergency restoration. System Operators and System Operator Supervisors have overall coordination and leadership of dispatching activities and make final decisions regarding restoration and system configuration issues. Specifically, the System Operators and System Operator Supervisors are responsible for: planning, coordinating, and directing of switching and tagging; writing, checking, and issuing clearances; monitoring loading and voltage; performing emergency restoration and associated reporting for the electric distribution system; and coordinating the above activities with other departments. System Operators and System Operator Supervisors complete appropriate documentation such as records outage remarks, cause codes, ETRs and similar.

Q. How does System Operations manage the transmission, distribution, substation, and network systems?

A. System Operations is the controller of the transmission, distribution, substation, and network systems used to energize or de-energize circuits or apparatus. No device under the control of System Operations, whether on a line or in a station, may be operated without permission from the System Operator, except under limited circumstances. The response of the System Operator always places the highest priority on public and

employee safety. Customer restoration is performed in a safe controlled manner, first attending to the paramount priority of public and employee safety.

For routine operations (non-storm), the System Operations Center is located in Berlin, Connecticut. The System Operators and System Operator Supervisors are available and responsible for the 24/7/365-day operation of the System Operations Control Center.

Q. Would you also explain the role and function of the Response Specialist Organization?

A. Yes. The Response Specialist Organization or "RSO" is a field organization that works in tandem with the SOC. The organization functions on a 24/7/365-day basis to provide public-safety coverage and emergency response to outage and trouble calls. "Troubleshooters" or "Response Specialists" are highly skilled, versatile line workers that serve in a first responder role in blue sky and grey sky operation and major storm restoration. The normal, full-time equivalent count is 126 Response Specialists. During routine operations, Response Specialists operate out of satellite centers and/or reporting sites that are dispersed across the service territory. The function of a reporting site is a place for the Response Specialist to assemble and pick-up their trucks and gear for the day's work.

Typically, Response Specialists are geographically dispersed across the system on round-the-clock coverage, but also can be regrouped in teams to work together if the actual restoration project requires additional support. Under the centralized

organization, Response Specialists are organized into five geographic areas or "zones" and are not bound (either organizationally or geographically) by the periphery of the Company's Area Work Centers or regional structure.

Response Specialists are deployed in a manner that: (i) assigns critical resources to those portions of the electric system that historically, and in the future, are more likely to sustain outages and trouble calls (not routine construction or new service work); (ii) incorporates travel distance/time concerns due to varied geography and development density across the CL&P service area; and (iii) incorporates varied customer density patterns. Priority 1 calls are typically received at the central dispatch located in the SOC in Berlin, CT, where the dispatcher identifies the fastest Response Specialist available. As these crews are dispersed across the system, the location of the AWC is not a factor in the time it takes an RSO to arrive at the site, assess the situation and make the site safe. Initially, when the Response Specialist organization was created, Response Specialists were deployed from the area work centers. Now, Response Specialists are deployed from 38 locations around the State, including the area work centers.

Q. How does CL&P monitor the health of the electric distribution system?

A. CL&P uses industry-recognized metrics to monitor the performance of its system, which are composed of the following: System Average Interruption Frequency Index ("SAIFI"), which measures how frequently a customer is interrupted on average;

System Average Interruption Duration Index ("SAIDI"), which measures the average interruption duration a customer might experience; and Customer Average Interruption Duration Index ("CAIDI"), which is the ratio of SAIDI and SAIFI, and typically measures how long an interruption event lasts on average or the average restoration time.

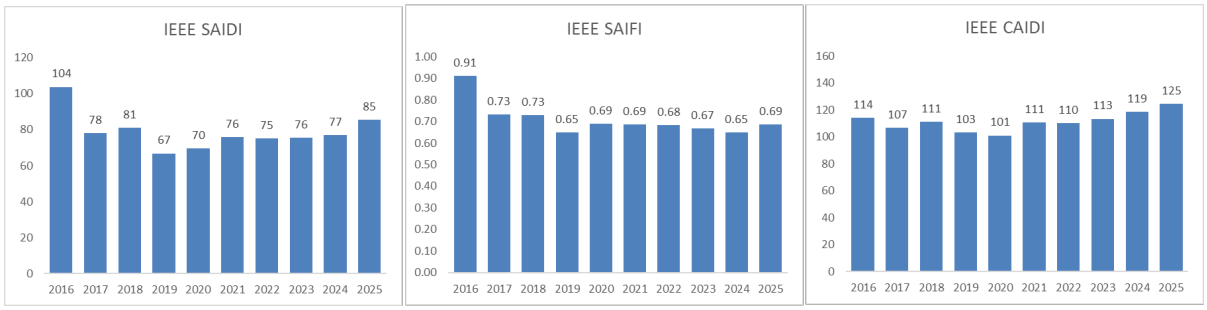
CL&P also tracks customer-centric metrics that help identify systemic outage issues for certain circuits, regions, or individual customers, which may be otherwise lost in traditional SAIFI, SAIDI, and CAIDI average measures. Specifically, CL&P tracks: Customers Experiencing Multiple Interruptions ("CEMI"); and Customers Experiencing Long Interruption Durations ("CELID").

For substation transformers, CL&P uses the Electric Power Research Institute (EPRI) Power Transformer Expert System (PTX), which factors in normal degradation, abnormal operating conditions, age and oil quality to establish Long-Term Health and Short-Term Health indices.

Q. What do the performance metrics tracked by the Company reveal about the performance of the electric distribution system?

As shown in the charts below, using the IEEE calculation methodology, SAIDI and CAIDI have been increasing in recent years, while SAIFI has remained flat.[9] This indicates longer outages, while the number of outages remains relatively the same.

Figure 6: Performance Measurements for 2016-2025, IEEE Methodology



Although Eversource's performance remains in the top quartile, it is currently on the lower edge of that quartile according to the IEEE benchmarking study.

Q. What factors are driving these performance trends?

A. Despite sustained investments by Eversource, CL&P's distribution system faces increasing operational risks due to the age, condition and structural limitations of key

[9] The Company calculates reliability metric values using three calculation methodologies. The first calculation methodology is the "TDRP Method," which was the methodology in place prior to the PURA's adoption of the Reliability Framework. In the TRDP Method, Major Storm exception thresholds are calculated based on the historical four-year rolling average number of trouble spots for all Major Storms previously excluded. The second calculation methodology presents the Company's reliability results consistent with the Reliability Framework ("RE08 Method") and the demarcation between gray and dark-sky events. The third calculation methodology ("IEEE Method") uses IEEE's classification of Excludable Major Event days. This is based on a daily SAIDI threshold (2.5 Beta method – Company level only), as compared to the TDRP Method and RE08 Method that are both based on a daily trouble spot volume threshold (Company or Division level). Also, the IEEE Method includes planned outage events, while the TDRP and RE08 Methods exclude planned outages.

assets. Equipment failures now account for approximately 35 to 40 percent of blue-sky outages, as aging infrastructure experiences higher failure rates due to deterioration and environmental exposure. This uptick in emergent repairs not only raises outage frequency but also diverts resources from proactive replacement and modernization efforts that promote cost efficiency over the long term given the ability to leverage "ahead of time" procurement strategies and other cost-saving techniques.

Q. How does the Company plan to address this reliability trend?

A. Improved system reliability supports affordability by reducing the frequency and duration of outages and the economic impacts that service interruptions impose on customers. The Company is committed to improving overall system reliability by reducing the frequency and duration of controllable outages. As discussed in Section IV, below, and in the testimony of the System Engineering Panel supporting the 5-Year TSP (Exhibit CLP-TSP-1), the Company intends to achieve this objective through strategic investments that: (1) maintain asset health through proactive programs that identify and address deteriorating assets before failure and replace aging infrastructure on a cost-effective basis; (2) expand system capacity to accommodate load growth from new commercial and industrial customers and increased electrification, thereby supporting broader utilization of the distribution system; and (3) advance long-term system modernization initiatives that enhance operational efficiency, effectiveness, and resiliency.

Additionally, as part of the PBMRP, the Company is voluntarily committing to two System Reliability performance incentive mechanisms ("PIMs") with performance-based benchmarks for SAIDI and SAIFI, as well as a Customer Reliability PIM seeking to reduce the number of repeat CEMI and CELID customers, predicated on PURA's approval of the PBMRP. These metrics are designed to ensure the Company maintains its high service quality standards during the PBMRP term and incentivize the Company to invest in a manner that cost efficiently benefits customers through improved reliability and resiliency. These and other performance metrics are discussed in Section V and Exhibit CLP-TSP-1.

IV. The Five-Year Targeted System Performance Plan.

Q. Please describe the Company's 5-Year TSP Plan.

A. As discussed by the System Engineering Panel (Exhibit CLP-TSP-1), the Company has developed a 5-year TSP Plan that would support the sequence of core distribution investments required to run the system, along with a longer-term view of system needs. The 5-Year TSP Plan integrates the Company's long-term planning, engineering, and system management disciplines into a comprehensive framework for identifying distribution system needs and prioritizing investments. More specifically, the 5-Year TSP Plan centers on five core system performance objectives:

1. **Reliability:** Maintaining high day-to-day service reliability so customers receive safe and dependable electric service;
2. **Capacity:** Ensuring the distribution system can meet current customer demand and anticipated load growth, including increased electrification and adoption of decarbonization technologies;
3. **Resiliency:** Strengthening the system's ability to withstand and recover from severe weather and other disruptions that threaten public safety or cause extended outages;
4. **Distributed Energy Resource Integration:** Enabling interconnection and effective use of distributed energy resources, including renewable generation and other non-traditional solutions that can support or defer traditional infrastructure investments; and
5. **Grid Modernization:** Transforming the distribution system into a more dynamic and intelligent grid through advanced technologies, automation, communications, controls, and innovative engineering. These improvements enhance operational efficiency, increase system visibility, and meet customers' growing expectations for reliable electric service.

Together, these critical performance objectives have shaped the Company's proposed investments and operational strategies for the next five years and lay the foundation for ongoing modernization in the years ahead.

Q. With reliability and affordability standing as significant considerations that the Company must factor into its operating decisions, what is the strategy that the 5-year TSP Plan incorporates to address these considerations?

A. The Company is acutely aware that its part of the affordability puzzle revolves around its ability to control O&M expense and to execute its capital work plan with rigorous authorization and oversight processes, cost controls, and efficiency. The primary strategy the Company seeks to expand across its asset health programs in the 5-year TSP Plan is a more proactive asset replacement approach. Replacing transformers and

aging poles, upgrading substandard equipment, and converting bare wire to more resilient configurations reduces the probability of failure before outages occur. Asset replacement also improves operational efficiency. Modern equipment is better suited to operate under changing climate conditions and evolving grid demands, including advanced system automation, increased electrification and higher DER penetration. Proactive upgrades ensure compatibility with modern technologies, enabling more effective system monitoring, faster fault isolation, and improved restoration performance. In addition, this approach directly improves customer reliability by preventing interruptions rather than reacting to them after the interruption has occurred. It also enhances public and worker safety by reducing the likelihood of downed wires, pole failures, and equipment malfunctions.

Although proactive replacement and upgrade programs require up-front capital funding, these programs are cost-efficient in the long run because work is routinely performed under normal operating conditions, leveraging straight-time labor and "ahead of time" vendor contracts that can provide preferred pricing and other benefits. Reactive replacement is emergent work that happens on an unplanned basis and must be addressed as circumstances occur so that the work is generally more costly overall. Emergent work—performed in response to unexpected equipment failures—is inherently more expensive due to the urgency, inefficient resource deployment, and extended outage restoration requirements. Similarly, storm response costs escalate when large numbers of assets fail simultaneously. By replacing assets before they fail,

the system experiences fewer cascading failures during storms, reducing both the scale and cost of storm restoration efforts, all else equal.

Managing asset health by expanding on the use of proactive replacements throughout the long-range plan will reduce catastrophic asset failures and longer-duration outages for customers, while limiting costs associated with emergent equipment failures and storm damage. In addition, as customer loading and usage patterns change, asset replacement and/or upgrades are required, making proactive replacement a good fit for these operating conditions.

The alternative—deferring investment—results in a steadily degrading asset base. As more equipment reaches end-of-life, failure rates increase, outages become more frequent and restoration times lengthen. This not only negatively affects customer convenience and welfare but also drives higher long-term costs and increased operational risk. As a result, a sustained, data-driven approach to asset renewal is essential to preserving system integrity and delivering reliable service to Connecticut customers now and into the future.

Accordingly, for this rate filing, the Company has devoted considerable effort to assessing, formulating, and validating an investment plan to support the identified system needs while balancing affordability considerations. As delineated in Exhibit CLP-TSP-3, the Company is presenting detailed information on the composition and derivation of the Company's proposed 5-Year TSP investment plan for PURA's review

and consideration. This background information is provided so that PURA can develop its own perspectives on the appropriate balance between system needs and the reasonableness of customer cost levels. There is a direct link between the rates that PURA sets in a rate proceeding and the tools the Company needs to implement to provide distinct service levels to customers. Therefore, the Company has worked to provide PURA with the visibility into how investment decisions impact customer reliability, and to align PURA's expectations for grid performance with customer costs.

Q. How can targeted capital investment help to reduce the cost of delivering electricity to customers in Connecticut?

A. It is broadly understood as a matter of industry practice that proactive distribution system improvements can help to reduce frequency and duration of interruptions for existing residential and commercial customers. What is not so well understood is that most assets that the EDCs replace are generally over 40 to 50 years old - assets that were sized to the system needs at the time of installation and generally not standardized. Today, every distribution line conductor or distribution transformer that the EDCs construct is standardized to support more efficient asset management and procurement. These standardized assets are typically larger and more efficient than legacy assets, providing a sharp increase in load carrying capabilities. As a result, the proactive replacements not only address poor reliability, age, condition or current loading conditions; the replacements also add substantial new capacity on the distribution system – capacity that can serve new customers looking for electric service, fuel

economic growth, integrate clean energy resources, and enable the electrification of transportation and heating sectors. Instead of adding incremental cost to drive those outcomes, the most efficient path is to use the planned distribution investments as an exogenous engine for growth**.**

Q. Would you provide an example of how this works as a practical matter?

A. Yes. One example is within the Eastern region of Connecticut, which includes the towns of Brooklyn, Union, Thompson, Eastford, Woodstock, Scotland, Voluntown, Sterling, Griswold, Plainfield, Canterbury, Killingly, Pomfret and Hampton, comprising approximately half of the territory of the Danielson area work center. The Substation Capacity plans in this region contemplate upgrades to Tracy 14M and Frybrook 13B, adding 22 MW and 31 MW of additional substation capacity, respectively. Load transfers from Brooklyn to Tracy will eventually result in 5 MW of additional capacity at Brooklyn 30Y. The substation upgrades and transfers would collectively enable over 13,000 conventional new homes or over 4,000 new homes with air-sourced heat pumps (ASHP) in the three substation service areas. In other words, these investments would enable approximately an 11% growth of residential customers in the region, all of whom could opt for fully electrified homes. Alternatively, the additional capacity in the Eastern region would enable 16 new (electrified) commercial developments or over 29,000 light duty EVs or significant fleet electrification. Additionally, 53 MW of new ground-mounted solar can be accommodated, and potentially significantly more, if facilities are co-sited with storage and developers use

onsite power management optimization or the Company's Flexible Interconnection offerings.

On the distribution line side, planned capacity and reliability improvements, as well as the System Resiliency Plan included in the 5-Year TSP, collectively, would upgrade 25 miles of old bare-wire overhead conductors to spacer cable and add 12 new automation sectionalizing devices. These upgraded lines provide access to the substation capacity, supporting residential and commercial end uses, load growth, electrification and clean energy adoption. For example, 19 gas stations along the upgraded distribution lines would be able to add EV charging infrastructure.

Most importantly, the overlapping investments to harden the Eastern region distribution grid and increase its capacity would result in higher reliability and resilience for new and existing customers. Residential customers in this region could potentially experience 30-40% reduction in the frequency and duration of power outages, depending on project specifics. Historically, outages in these areas have impacted up to 10,000 customers and approximately 20 critical facilities across multiple towns. Included within this scope are three locations where approximately 114 customers have experienced more than 10 storm-related outage events over the past four years. The fact that these capacity and reliability improvements impact three distressed municipalities (Killingly, ranked 22nd in the state; Plainfield, ranked 9th in the state; and Sterling, ranked 2nd in the state), is evidence that the investments can

equitably provide safe, reliable, resilient energy for Connecticut customers. The Eastern region would also benefit from statewide modernization plans like the Implementation of an Advanced Distribution Management System (ADMS) driven - fault location detection and restoration, voltage control, DER forecast and dispatch and an advanced DER communication system, that would even further enhance the benefits of foundational infrastructure investments.

Q. In this context, what is the fundamental impetus for implementation of a targeted system resiliency plan?

A. The distribution system is built with redundancy, principally circuit ties and back-up sources, sized to automatically re-route power around a single point of failure. This design provides reliable service under normal operating conditions and during minor storms. In a major storm, however, multiple failures occur simultaneously, and the primary and back-up sources may be affected at the same time, limiting the restoration options the design depends on. A different category of investment, system hardening, is required to close this structural gap.

Second, the root cause of storm outages is a structural mismatch: bare wire in high tree-conflict corridors. Approximately 47 percent of the overhead system, roughly 7,500 miles, remains bare, uninsulated wire with no protection against tree contact. Any wind-driven branch, limb, or falling tree that contacts bare energized conductors potentially creates a fault and a momentary or sustained interruption for every customer downstream. This construction was cost-justified given the prevailing weather patterns

and customer expectations when it was installed; but that calculus has changed materially. The data confirm the consequence: tree and limb contact causes roughly 68 to 72 percent of outage events on storm-active days, and the zones that combine bare wire with the heaviest vegetation fail repeatedly, storm after storm.

Third, storm frequency and intensity are increasing at both ends of the spectrum. Connecticut has experienced four once-in-a-generation storms in the past fifteen years (Irene and Alfred in 2011, Sandy in 2012, and Isaias in 2020), each producing outages affecting more than half the system; in these events approximately 70 percent of the total customer minutes of interruption (CMI) resulted from backbone failures, which interrupt every customer downstream of the failure point. Equally important, the system now experiences a steady cadence of smaller storms, approximately 30 to 45 storm-active days per year, and these days account for roughly 75 percent of total annual CMI. The need is therefore driven not only by the rare catastrophic storm, but also by the cumulative, recurring impact of the many smaller storms.

Fourth, the forest and tree conditions surrounding the system have changed. Connecticut is simultaneously one of the most densely populated and most heavily forested states in the nation, with approximately 75 to 78 percent forest cover and about 85 percent of forest trees more than 61 years old. This aging, expanding canopy grows directly into and over rights-of-way. Vegetation management, while essential, cannot eliminate the exposure, because regrowth re-establishes hazard conditions within two

to four years and trees outside the trimmable right-of-way still fall onto lines during storms.

Fifth, customer expectations have risen. The legacy bare-wire system performed acceptably during an era of lower customer dependence on continuous electric service. Today, customers and the broader economy rely on uninterrupted power to a degree the legacy system was never designed to support.

A targeted resiliency plan focuses investment where it will be the most beneficial, which is on the proven, high-failure locations that have experienced multiple storm-driven outage events in recent years; typically bare wire in heavy-tree conditions, that fail under storm duress.

Q. Given these investment drivers, how does the Company plan to meet today's expectations and tomorrow's needs for the electric distribution system?

A. The Company's core strategy for meeting today's expectations and tomorrow's needs centers on proactively replacing assets. By replacing aging poles, upgrading outdated equipment, and converting bare overhead wire to more resilient designs, the risk of failures and outages is reduced before problems arise. These investments not only bolster operational efficiency by aligning with current engineering standards and supporting advanced automation, but also accommodate the evolving needs of the grid, including increased electrification and distributed energy resources. Modern equipment improves system monitoring, enables faster fault detection and isolation, and streamlines service restoration. Through this forward-looking approach, the

Company will enhance reliability, strengthen public and worker safety, and minimize the chances of equipment failures, downed wires, and pole-related incidents.

Q. What are the investment levels that the Company has identified for the 5-Year TSP?

A. As shown in the table below and discussed by the System Engineering Panel in Exhibit CLP-TSP-1, the Company has provided information on three capital-investment approaches, each associated with a different goal for system performance. These three levels begin with a baseline level of core investment necessary to sustain the system ("Sustained Performance") and progress to the second tier of investment that would provide the resources necessary to improve reliability performance and institute a dedicated resiliency program improving performance during both blue-sky days as well as during storms. This second tier encompasses investment for both Sustained Performance and Enhanced Reliability and Resiliency Performance and requires a higher investment level than the Sustained Performance on its own. In this proceeding, the Company's proposal is to implement the second tier investment level, encompassing sufficient resources to sustain the system and to address enhanced reliability and targeted resiliency work.

Third, the Company has identified a forward-looking modernization strategy designed to align the grid with current industry standards and emerging customer and policy needs. The level of investment needed for this tier is higher and will likely take time to reach as a practical matter.

Table 1: The 5-Year Targeted System Performance Plan
Sustained Performance + Enhanced Reliability & Resiliency

Performance Area	Sustained Performance	Enhanced Reliability and Resiliency	Advancing the Grid
Primary Objective	Safe, maintain reliability, and meets Planning Criteria	Accelerated system hardening and reduced storm cost	Modernize the grid to current industry standards
Operational View	Stability-focused	Improved storm performance	Proactive and strategic
Safety & Compliance	Supports evolving regulatory requirements (e.g., RE08)	Supports evolving regulatory requirements (e.g., RE08)	Exceeds minimum standards through risk-based investments
Reliability Performance	Maintained at current levels	Improved reliability and resilience system performance	Improved performance through proactive asset health
SAIDI / Customer Impact	Stabilized customer performance	Reduced outage frequency and duration and improved customer experience	Reduced risk and improved system configuration
Emergent Failures	Minimal impact	Reduced through resiliency upgrades	Further reduced through proactive replacements
Asset Health	Targeted replacements to prevent failures	Improved right-of-way, old bare wire and aging substation asset replacements	Accelerated, condition-based asset renewals
System Capacity	Meets planning criteria, focused on 10-year violations	Meets planning criteria, focused on 10-year violations	Proactive Solar Enablement
Automation	Maintains system automation (DMS, DERMS)	Increased system automation	Expanded automation to improve restoration and efficiency
Resiliency (Storm Cost)	No dedicated resiliency investment	Proactive, system-level resiliency investment, storm cost reduction	Further improved through proactive asset replacement
Cost Trajectory	Lower near-term spend; higher Emergent and capital risk	Increased system investment to reduce storm operating cost	Higher upfront investment; lower long-term operating cost
Regulatory Policy	Set foundation for PBR, reduced regulatory risk (RE08)	Regulatory aligned	Aligned with lower regulatory risk in outer years

Q. If the 5-Year TSP proposed by the Company encompasses Sustained investment plus the Enhanced Reliability and Resiliency component, what is gained in this second tier?

A. The Company has structured the 5-Year TSP to incorporate both Sustained investment and the Enhanced Reliability and Resiliency component because incorporating the incremental tier would yield important benefits for customers, particularly over the long term, without increasing costs to an "unaffordable" level. For example, the System Resiliency component accounts for the majority of the incremental cost, with a budget of $156 million over five years. Together with the Enhanced Reliability components, the incremental investment required to support this tier is approximately $75 million annually, on a combined basis.

The Enhanced Reliability component would address asset health through the completion of additional proactive replacements beyond what is included in the Sustained investment level. The System Resiliency component would be additive, involving system upgrades across the Company's three operating regions for system-hardening, targeting "priority zones" within each region. The priority zones are areas on the system where outage events affecting more than 1,000 customers have occurred during at least one storm event in the past four years involving bare-wire overhead conductors. The "All-In SAIDI" metric is used to rank circuits by total predicted impact. All-In SAIDI combines historical SAIDI measurements under blue sky and grey sky stormy weather conditions, and an assumption of a 1-in-10-year catastrophic storm.

Q. Why is the Company proposing a System Resiliency component for the 5-Year TSP?

A. Resiliency investments address customer affordability in three important ways.

First, resiliency investments enhance reliability not only during catastrophic weather events but also during the more common, lower-intensity storms customers face each year. Connecticut experiences approximately 30–45 storm-active days annually, and these events account for more than half of all customer outages. By strengthening the electric system, the Company lowers both the frequency and severity of outages during major and routine storms.

Second, system hardening reduces restoration costs and speeds up service recovery. Investments such as stronger Class 2 poles reduce infrastructure failures, allowing crews to restore power more rapidly and efficiently, while preventing more extensive and costly repairs. These operational savings directly benefit customers.

Third, the Company's resiliency strategy achieves significant reliability improvements at a fraction of the cost of full undergrounding. For instance, spacer cable reconductoring delivers nearly two-thirds of the resiliency benefits of undergrounding for only about one-third of the cost. This cost-effective solution maximizes customer value and expands resiliency benefits to more customers.

Q. Are there other benefits of implementing the System Resiliency component.

A. Yes. The System Resiliency component is a customer and equity-focused, high-impact program that delivers measurable benefits to customers and communities. The program would harden approximately 105 miles of overhead lines by replacing bare wire, serving about 60,000 customers in 68 towns statewide and protecting roughly 90 critical facilities, including medical and emergency services facilities. The plan's broad geographic scope is intentional, ensuring equitable distribution of benefits.

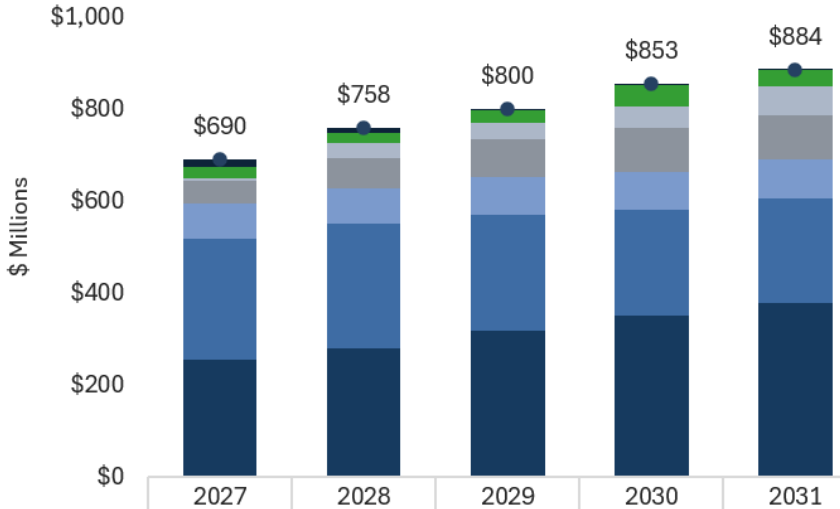
The plan delivers measurable performance and economic benefits. Hardening these zones is projected to save approximately 12.4 million customer-minutes of interruption annually. Using the Company's estimate of $3 per customer-minute for the value of lost load, this translates to about $37.1 million per year in avoided customer impacts. The plan also enhances restoration capabilities: approximately 40 tie reclosers will enable faster automated switching and quicker restoration during outages. Lastly, the plan is grounded in a clear equity commitment: it prioritizes areas with the highest Storm-CEMI, ensuring that the most storm-impacted customers are served first, and then it optimizes the remaining zones for maximum statewide reliability.

Q. What is the total projected cost of the Company's 5-Year TSP, including the System Resiliency component?

A. The 5-Year TSP is designed as a system performance plan encompassing program components that drive performance across the system. The funding necessary to support the 5-Year TSP is not the total capital funding needed to support CL&P's entire

business across an operating year. For example, CL&P also has funding requirements for its work facilities and information systems. The figure show the total capital dollars needed to support CL&P's system over the next five years in major expenditure categories. These expenditure categories include the estimated expenditure associated with the Company's proposed 5-Year TSP.

Figure 7: CL&P Capital Funding Requirements (2027-2031)



	2027	2028	2029	2030	2031
Information Technology	$18	$10	$5	$1	$1
Facilities	$23	$24	$25	$47	$36
Regulatory Commitments-ED	$6	$31	$36	$46	$61
Peak Load / Capacity-ED	$50	$67	$84	$96	$96
New Customer-ED	$75	$77	$80	$82	$86
Basic Business-ED	$264	$269	$252	$231	$226
Reliability-ED	$254	$280	$319	$350	$378
Total	$690	$758	$800	$853	$884

Q. Please elaborate on the nature of the investment categories shown in the figure above.

A. Capital needs associated with "Basic Business" functions, including upgrades to telecommunications infrastructure, IT systems, facilities, vehicles, street lighting, and tools are categories of capital expenditure that CL&P incurs, outside the system engineering and construction function. These items include insurance claims, environmental mitigation costs, meters, state-mandated line relocations, and double pole removals. The average five-year investment in these excluded programs is approximately $155 million per year. The remaining categories are engineering classifications, as follows:

Reliability – Core: Core capital is divided into four sub-categories: Basic Business, Reliability, New Customer and Peak Load Capacity projects. The average five-year investment in these core programs is approximately $568 million per year.

1. Basic Business: This category includes pre-capitalized transformers—smaller, long lead-time distribution line transformers purchased in advance to ensure timely customer connections and facilitate equipment upgrades as needed throughout the year. It also covers emergent replacements of failed distribution line and substation equipment. These investments are termed Basic Business because the Company has no discretion in incurring these costs; they are essential to maintain service and system reliability.

2. Reliability: Reliability projects are further divided into five categories: Distribution Line Reliability, Network Reliability, Substation Reliability, Expanded Reliability, and Underground Cable Reliability. Investments in each program are aligned with historical spending patterns, with reasonable escalations to reflect asset age, condition, and overall degradation.

Distribution Line Reliability: These programs focus on replacing aging overhead infrastructure, implementing annual small-scale tactical upgrades, facilitating line extensions to retire obsolete end-of-life stations, and undertaking specific projects necessary to maintain SAIDI and SAIFI reliability performance. A significant portion of the investment targets the daunting task of replacing approximately 3,700 miles of bare copper wire over 189 years, which is a leading contributor to conductor failures. The line extension work is projected to take more than 19 years to retire single-ended, islanded stations that expose customers to single points of failure. Projects may also involve sectionalizing through smart switch and trip-saver deployment, as well as reconductoring, to address reliability issues on historically poor-performing circuits in the most cost-effective manner. The Company uses a proprietary Benefit-Cost Analysis (BCA) model, developed from historical experience with reliability projects and associated improvements in SAIDI and SAIFI.

Network Reliability: These programs focus on the annual replacement of aging network transformers and protectors, Paper Insulated Lead Cables (PILC), aging pad-mounted switchgear, vault and manhole rebuilds, and the installation of energy release manhole covers. Each project addresses critical safety risks. Notably, these investments aim to complete the replacement of obsolete PILC cables within 25 years, aging pad-mounted switchgear within 41 years, and the installation of energy release manhole covers within 10 years. The Company prioritizes replacements based on risk, targeting the oldest assets and those identified through inspection findings.

Substation Reliability: These programs focus on replacing aging substation transformers, switchgear, load tap changer controls, and other critical substation assets such as relays, switches, and station service equipment. Investments in substation asset health are essential for sustaining safe and reliable electric service through the prudent management of Connecticut's aging substation infrastructure. Much of the state's substation system was built during the major expansion of the electric grid from the 1940s to the 1970s. While many assets have operated reliably beyond their original design lives due to effective maintenance and operational practices, a significant portion of the fleet is now between 50 and 80 years old. As these assets continue to age, both the likelihood and the potential consequences of failure increase—especially equipment that serves critical system functions. Eversource employs a risk-

informed asset management approach, prioritizing replacement of the highest-risk assets based on their condition, criticality, performance history, and impact on reliability. This targeted strategy addresses the growing concentration of aging infrastructure, ensuring capital is deployed where it delivers the greatest value and risk reduction—balancing system reliability, public safety, and customer affordability.

Expanded Reliability: These programs focus on removing more than approximately 15,000 hazard trees along Connecticut distribution circuits, replacing over 1,000 poles per year that do not meet NESC safety standards, and addressing more than 10,000 right-of-way (ROW) poles over 50 years old. Fully replacing these ROW poles would require 31 years, as the Company sizes these programs according to historical spending patterns, with reasonable escalations to reflect the deteriorating condition of these assets.

Underground Residential Development (URD) Cable Reliability: This program targets the replacement of specific sections of direct-buried cables that have experienced multiple documented failures. Of the 5,500 miles of URD cable in the system, the Company prioritizes replacements using a data-driven approach, balancing investment levels with historical spending and applying reasonable escalations as necessary.

3. New Customer: This program covers the non-discretionary costs of connecting new customers, after accounting for their contributions to upgrade expenses. Spurred by economic development, customer connection costs in the state have risen by 27% over the past five years.

4. Peak Load Capacity: This program involves replacing distribution line and substation transformers expected to exceed the Company's planning criteria over the next ten years. Approximately one-quarter of substations are projected to surpass their firm capacity within this period. These investments address violations of planning criteria and are critical to maintaining current reliability performance over the foreseeable future.

Incremental – Reliability and Resilience: Incremental capital is divided into four sub-categories: Customer-Focused Reliability, Reliability, ISO-NE OP-17 Compliance, and the DERMS Program. These initiatives are specifically intended to expand investments beyond the 10-year average and to improve reliability performance, rather than simply maintaining current levels. The average five-year investment in these programs is approximately $75 million.

Customer-Focused Reliability: In response to the 17-12-03RE08 docket, which mandated the creation of town-level scorecards, the Company reports not only on statewide SAIDI and SAIFI reliability metrics but also on performance within specific towns. As a result, the Company targets poor reliability in customer load pockets or towns with below-average service. Incremental

investments in this category are justified using town-level SAIDI and SAIFI reliability data.

Reliability: Reliability projects are further categorized as Distribution Line Reliability and Substation Reliability.

Distribution Line Reliability: These programs focus on the accelerated replacement of aging overhead infrastructure, pad-mounted network switchgear, and Paper Insulated Lead Cable (PILC). As a result of these investments, the time frames for the total replacement of overhead bare wire are reduced from 189 to 144 years, pad-mounted switchgear from 41 to 18 years, and obsolete PILC cables from 25 to 17 years.

Substation Reliability: These programs focus on the accelerated replacement of aging substation transformers and equipment. The goal is to ensure that the oldest transformers in the fleet are no older than 70 years within ten years, and to minimize the risk associated with obsolete station equipment.

ISO-NE Compliance: This program focuses on redesigning distribution capacitor banks—optimizing their size and placement—to reduce leading power factor during light load periods. It also addresses the need to limit VAR injection from the distribution system to the

transmission system, ensuring compliance with ISO-NE OP-17 procedures.

DERMS: This program implements Grid DERMS with distributed energy resource (DER) forecasting capabilities in Connecticut. Grid DERMS represents a significant advancement as EDCs transition toward the Control Room of the future—leveraging Advanced Distribution Management Systems not only to pinpoint fault locations and reconfigure the distribution system to isolate faults, but also to utilize DERs to maximize customer restoration and grid resilience.

Resilience: The resilience plan targets bare wire in the worst tree-condition corridors, selected two ways: 12 locations that experienced ten or more storm events in the past four years, plus additional zones with the highest predicted benefit from All-In SAIDI model, assuming a 1-in-10-year ISAIAS-level event. Together, these 59 zones cover 105 miles of spacer cable reconductoring – a solution that's 62% effective at preventing storm outages at one-third the cost of undergrounding. Each zone experienced at least one storm event in the past four years – ensuring that the predictive model's benefits are grounded in demonstrated vulnerability, not projections alone.

V. The Performance-Based Multi-Year Rate Plan.

Q. What is the Company proposing as a structure for a performance-based multi-year rate plan, or PBMRP?

A. The Company's proposed PBMRP generally follows a traditional structure for a performance-based ratemaking plan, with features and mechanics that are consistent with PURA's preliminary steps on a PBR framework in its uncontested dockets. The PBMRP is designed to support the implementation of the 5-Year TSP and to create strong incentives for cost and operating performance. Our testimony below describes each element of the PBMRP.

As the Company prepared its filing, it became clear that the path forward for electric customers requires a creative, holistic, in-depth approach to achieve an outcome capable of powering Connecticut's future at a cost that customers can manage and afford. Thus, the Company's PBMRP proposal is designed to provide PURA with a path forward for the delivery of safe, reliable, resilient and affordable electric service, which necessarily has to include a path for recovery of capital investment.

Q. Is capital investment needed to serve the interests of customers, or is it simply a path to profits?

A. In the rate-setting process, electric utilities earn a return on prudent capital plant additions and, if rate base is relatively bigger, the return on that rate base will be relatively bigger. However, if the thinking stops there, then reality is not a consideration. An electric utility looking to maintain a level of financial integrity simply cannot race around its system to complete every bit of capital investment that it

can envision on its distribution system, piling up plant additions to enter rate base at the next ratemaking juncture – and be successful in maintaining its financial integrity. In fact, this type of approach would be thoroughly debilitating to the financial integrity of the utility for numerous reasons, not the least of which is that capital resources are "scarce," particularly in relation to the amount of investment that an electric distribution system requires to stay healthy and resilient. In the Northeast, where CL&P has operated for over 100 years, electric systems are aging and outmoded by advancing technology and operating practices and constant, consistent investment is fundamentally vital to maintain the system in any sort of reasonable working order.

As a public-service company, the distribution system is charged with meeting numerous performance goals, each requiring substantial quantities of consistent, targeted investment, including that: (1) the system needs to be *safe* for the public and for employees working on the system to provide service to customers on a 24/7/365 basis; (2) the system design and distribution assets must be capable of delivering a *high level of reliability* under a range of planning scenarios and operating conditions, so that customers have electricity when they need it; (3) the system must have *sufficient capacity* to accommodate current and future customer load demand, particularly in an environment where policy objectives are pushing forward on electrification and decarbonization goals;[10] (4) the system must have *resiliency* to withstand increasing

[10] With each capacity upgrade, the system is better prepared for electric-vehicle adoption, heat-pump conversions and other electrification, as well as solar enablement. Thus, the Company's investment in reliability, resiliency, and capacity upgrades has a ripple effect from a public-policy standpoint.

damaging natural forces that will inevitably impact the distribution system in an era of climate change, as prolonged outages threaten the public safety and are disruptive and costly for customers; (5) 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 (6) 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. And, overarching all these critical system goals, is the need for customer affordability.

Accordingly, for a system the size of CL&P's, there must be constant attention on all corners of the system and investment needs to be allocated to these goals on a consistent basis while maintaining a line of sight to customer bill impacts.

Q. What does this mean for the implementation of a performance-based ratemaking framework?

A. It means that investment must happen. And, where investment must happen, it is necessary for the applicable ratemaking procedures to be reasonably supportive, although doing so in a manner that is cost-effective and reasonable for customers to bear from a bill impact perspective. For the Company's part, it seeks to implement 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.

For PURA, it is imperative that it consider that rate-recovery will happen – it is only a matter of how and when with the alternatives limited to: (1) a cycle of base-rate proceedings, sequenced successively to capture cost changes and updated plant additions; or (2) a multi-year rate plan that encompasses features to allow for some stability and predictability in terms of both the revenues that the utility will receive and the bill impacts to customers. This is the fundamental policy decision that PURA must make in this proceeding. To that end, the Company recognizes that, without a clear understanding of where the CL&P system stands in relation to the electric system's vital performance obligations, it will be difficult for PURA to gauge the reasonableness of costs that customers will ultimately be asked to bear in relation to their electric service, or alternatively, in relation to the broader role that the electric system plays in supporting Connecticut's economy and commerce, public health and safety, and state policy and climate goals. The Company has developed the 5-year TSP Plan for this purpose so that PURA has a line of sight to be able to trace what the Company is working to achieve and what the Company is requesting that PURA provide for revenue support.

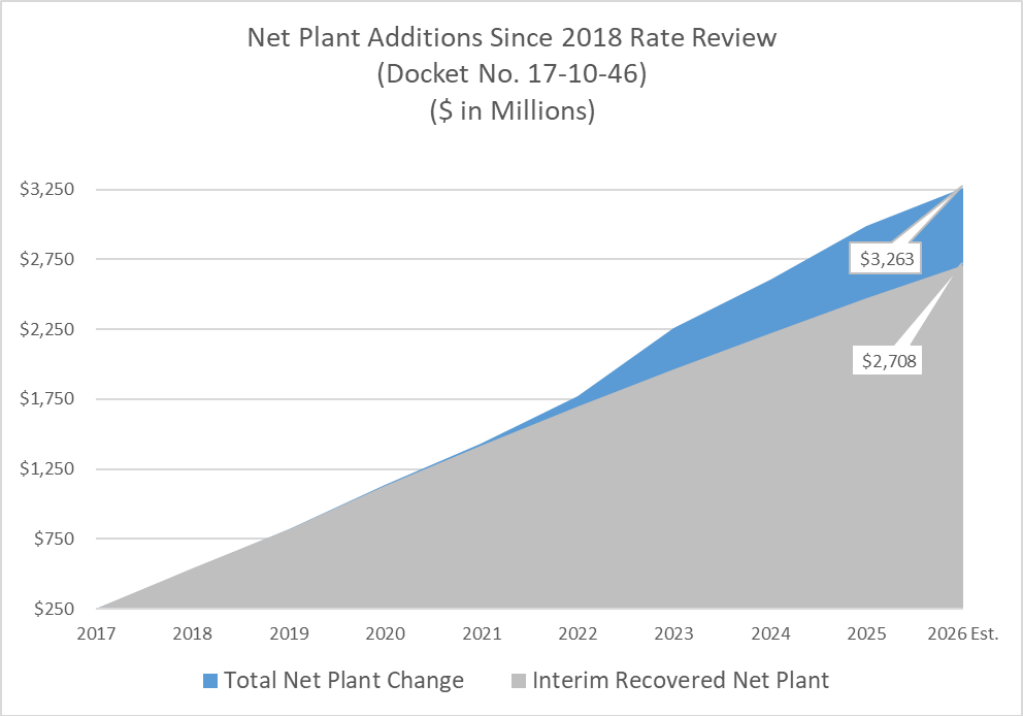
Q. Is there a basis for the Company's perspective that a multi-year rate plan providing annual revenue support for capital investment is in the best interests of customers?

A. Yes. The 2018 Rate Settlement established a multi-year rate plan and the Electric System Improvements rate recovery mechanism to permit recovery of costs incurred annually to upgrade, replace and reinforce electric distribution infrastructure for the benefit of customers.[11] Through the multi-year rate plan, the ESI rate was gradually increased such that the bill impact for customers was limited to less than $2 per month each year, on average, over an 8-year period, 2018-2025, while allowing the recovery of the costs associated with $2.7 billion of invested net capital for infrastructure upgrades. This gradual roll-in of invested capital has greatly benefitted customers because – without the ESI – customers would now be facing a rate increase to accommodate $3.3 billion of incremental net capital invested since the 2018 rate review, instead of the $600 million that remains to be incorporated into rates over and above what the ESI will address through December 31, 2026. The mitigating impact of gradual increases accomplished through the ESI from 2018 to 2026 is illustrated in Figure 8, below. Only the area shaded in blue in Figure 8 remains to be incorporated into customer rates, demonstrating that the ESI rate mechanism has operated effectively to support needed capital investment on a year-to-year basis, while dramatically

[11] The ESI allowed recovery of capital investment above $270 million for the years 2018, 2019 and 2020, and for up to $300 million in core capital placed in service in the years 2021 through 2025.

mitigating the bill impacts that customers will experience as a result of this distribution rate review.

Figure 8: Net Plant Additions 2017-2026



All else equal, the operation of the ESI has reduced the estimated, proposed monthly bill impact for the Company's upcoming rate review by approximately 40 percent, from the range of an estimated $40 per month to a range of an estimated $25 per month, excluding the impact of major storm cost recovery. Due to a change in legislation enacted in 2023,[12] the ESI will terminate on the date that new rates are set in this rate proceeding. However, PURA needs to consider the tangible benefit

[12] Public Act 23-102, *An Act Strengthening Protections for Connecticut's Consumers of Energy*, Section 5.

that customers gained from this type of rate structure, stabilizing rates for customers so that rate changes were smaller and easier to adopt to, as compared to a base rate change that would have to incorporate all of this investment in one fell swoop. This valuable experience gained with the ESI supports the implementation of a multi-year rate plan that can harness the strong stabilizing impact that more gradual increases produce for customers, as compared to larger aggregated base-revenue increases imposed every few years.

A. The Revenue Deficiency and Its Drivers

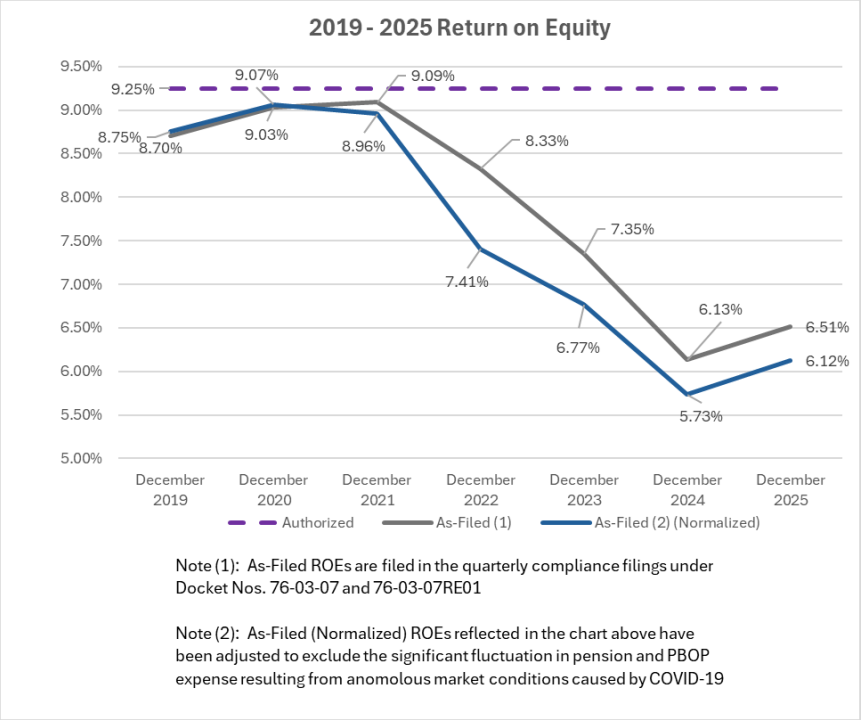
Q. When were CL&P's distribution rates last reviewed and set by PURA?

A. CL&P's distribution rates were last set in an April 2018 PURA-approved rate case settlement agreement, with rates effective May 1, 2018, and incremental step adjustments effective May 1, 2019, and May 1, 2020. Since that time, CL&P has consistently provided customers with high-quality service, made substantial investments in distribution infrastructure, and steadily navigated through extraordinary challenges, including the COVID-19 pandemic.

Q. Has CL&P earned its authorized return on equity since PURA last set rates?

A. No. PURA authorized an ROE of 9.25 percent as part of the 2018 Settlement Agreement approved in Docket No. 17-10-46. As shown in the figure below, the Company has not earned its authorized return in any year since that time. Most recently, the Company's normalized earned ROE has been in the range of 5.73 percent to 6.12 percent, which is significantly lower than CL&P's authorized ROE.

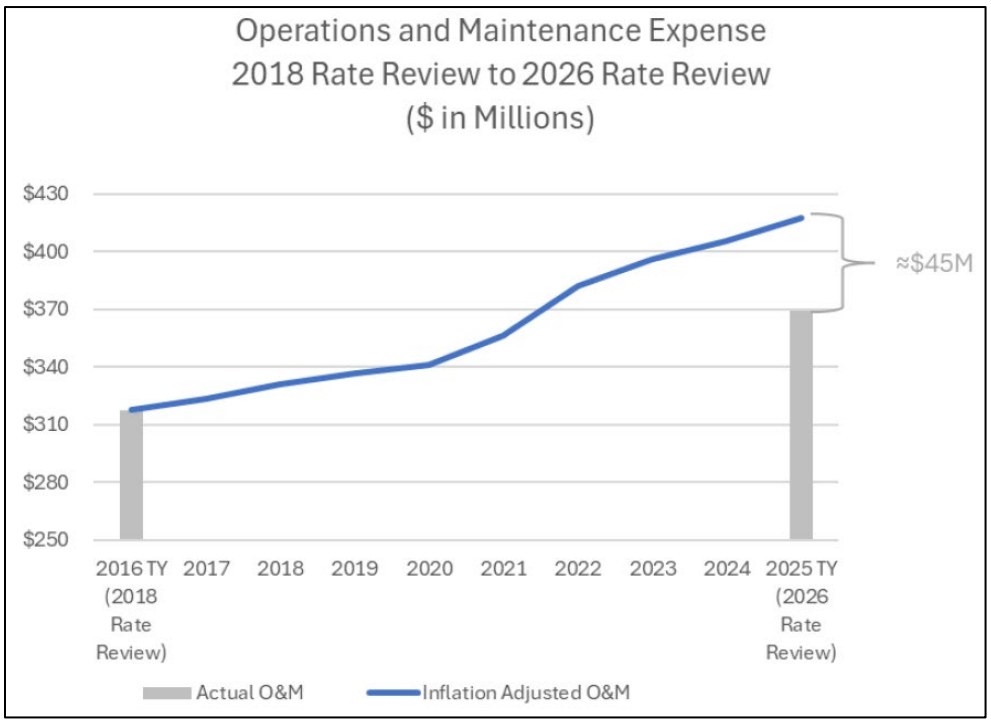
Figure 9: CL&P Earned vs. Authorized ROE



Q. Please discuss the Company's O&M expense track record since the Company's 2018 rate case.

A. As shown in the figure below, the Company's O&M spending has tracked below inflation from 2016 to date, demonstrating that the Company has prudently managed its operating costs and exercised cost discipline despite facing the same inflationary pressures as the broader economy.

Figure 10: Operations & Maintenance Expense Trends



Q. Please describe the Company's request for a change in base rates.

A. The Company is requesting that PURA approve new delivery rates to alleviate a base revenue deficiency of approximately $451 million, before accounting for the impact of storm costs from 2018 to March 2025. The total revenue deficiency in the Rate Year, inclusive of the impact of 2018 through March 2025 storms, is approximately $727 million.

The Company's proposed base-rate change is based on a cost of service measured by a test-year ending December 31, 2025, adjusted for known and measurable changes. The proposed revenue requirement is based on a total average rate base of $6.8 billion and

an overall weighted cost of capital of 7.74 percent, reflecting a proposed return on equity of 10.25 percent. The total average rate base reflected in the proposed revenue requirement is the product of $9.798 billion of average plant in service, plus the cost of removal, less accumulated depreciation and accumulated deferred income taxes incurred since the Company's last distribution rate case in Docket No. 17-10-46.

If the Company's total revenue deficiency inclusive of storms were approved, a typical residential customer consuming 700 kWh per month would, on average, experience a total monthly bill increase of $32.91 or approximately 18 percent, effective July 1, 2027.

The Company's filing includes the calculations and workpapers for the proposed revenue requirement, an updated depreciation study, a total factor productivity study in support of the Company's PBRM, an allocated cost of service study, and a marginal cost of service study.

Q. What is driving the base revenue deficiency?

A. As shown in the figure below, the base revenue deficiency is primarily driven by the costs required to provide safe and reliable electric distribution service for an aging and growing system. These costs include increases in rate base from plant already in service, corresponding depreciation and cost of capital, operations and maintenance expenses (mainly labor and vegetation management), storm-related expenditures, and taxes.

Figure 11: Revenue Deficiency Drivers ($ millions)



B. The Proposed PBMRP

1. Overview

Q. Why does it make sense for PURA to approve the implementation of a performance-based multi-year rate plan at this time?

A. A PBMRP framework more effectively aligns regulatory objectives with incentives for operational efficiency than traditional cost-of-service regulation. Although the traditional cost-of-service framework serves a critical purpose, it falls short on providing a strong incentive for ongoing productivity improvements between rate cases – and the shorter the cycle is between rate cases, the weaker the incentive for "stretch." The Company's experience is that the "stretch" is the most effective dynamic in a PBR plan for achieving cost efficiencies.

A PBMRP framework shifts this dynamic by providing stronger incentives for management to pursue efficiencies, increase productivity, and control costs over a

defined period. At the same time, customers share in the benefits of those efficiencies through built-in PBMRP mechanisms, such as the Consumer Dividend, while also benefiting from a more stable and predictable rate trajectory that reduces future revenue deficiencies and the associated bill impacts for customers.

Q. Are there administrative benefits associated with the PBMRP?

A. Yes. The PBMRP has a four-year stay-out period, which reduces the frequency of resource-intensive rate case proceedings. This benefits not only CL&P, but also PURA staff, the OCC, intervenors and other stakeholders. The resources that would otherwise be devoted to repeated rate case preparation and litigation can instead be focused on other priorities.

Q. Will the proposed PBMRP reduce PURA's oversight?

A. No, not at all. In fact, the proposed PBMRP will enhance PURA's regulatory oversight by establishing regular reporting requirements and performance metrics that increase transparency, align utility incentives and regulatory objectives, and maintain accountability. Rather than concentrating regulatory review in a single rate case every few years, the PBMRP provides PURA with regular opportunities to review and evaluate the Company's performance, track costs and investments, and ensure that customers receive the benefits contemplated in the plan.

Q. What would happen if PURA does not approve the proposed PBMRP?

A. If PURA does not approve the proposed PBMRP, the Company will plan to file traditional rate cases for CL&P, as close to annually as possible. The Company has spent three years developing the 5-Year Targeted System Performance Plan, beginning with PURA's issuance of a final decision in Docket No. 17-12-03RE08, which made it clear that system investments needed a deeper analytical basis. With this work completed, it is clear that the Company needs to increase its investment in the system on a gradual, systematic basis and to refocus that investment to cover a range of items on the system, all necessitated by the need to make sure that "sustained" performance will be maintained and improvements to reliability and resiliency made possible.

Q. Please summarize the primary components of the Company's proposed PBMRP.

A. The Company's proposed PBMRP mechanism adopts the fundamental methodology of a traditional, comprehensive PBR plan, except that it provides a formula-based adjustment for only the O&M components of the Company's revenues. A traditional PBR plan typically applies to a utility's total revenues and implicitly allows recovery of both O&M and capital costs through performance-based methods. In contrast, the proposed PBMRP mechanism applies only to the Company's O&M costs. As discussed later in this testimony, the Company's is proposing a separate funding mechanism for capital investments.

The Company's proposed PBMRP is designed around a "revenue cap" formula that adjusts rates annually over a four-year "stay out" period. This framework sets a base

revenue level and applies a formula-driven adjustment each year during the term. The Company proposes that the PBR adjustment go into effect annually on July 1, with the first PBR adjustment taking effect on July 1, 2028, the next on July 1, 2029, and the last on July 1, 2030.

The components of the PBR Plan are: (1) a partial revenue cap formula that adjusts O&M in the approved revenue requirement on an annual basis to reflect cost trends in the industry; (2) a "stretch factor" (S-Factor) or Consumer Dividend; (3) an earnings-sharing mechanism; (4) an exogenous events provision; and (5) a separate capital funding mechanism to account for the increasing need for incremental investment on the distribution system. Each of these components is described in detail below.

In addition, the Company's proposed PBR formula is detailed in the Company's proposed rate tariff. However, the simplified version of the PBR formula is:

$$Rev\ Requirement_t = \left(O\&M\ Rev\ Requirement_{t-1}\ x\ (1 + I_t - X - CD)\right) + F_t + Z_t + ESM_t$$

Where:

Rev Requirement$_t$ = the revenue requirement in the current (forecast) period

O&M Rev Requirement$_{t-1}$ = the approved O&M -related revenue requirement starting with the authorized O&M in this proceeding and adjusting annually based on this formula.

I = Composite O&M Index (ECI and GDP-PI) and must be non-negative

X = -0.03

CD = a consumer dividend that is a minimum of 30 basis points and adjusts annually depending on O&M Cost performance per customer, relative to benchmark performance

F = capital cost recovery mechanism to support necessary system investments

Z = an exogenous cost adjustment

ESM = earnings sharing adjustment

Together, these elements establish a framework that promotes efficiency, supports ongoing investment in safe and reliable service, and ensures customers have appropriate protection and opportunities to share in the PBMRP's benefits.

Q. Having provided an overview of the PBMRP and its expected benefits, would you cover some of the specific aspects of the PBMRP?

A. Yes. With respect to the specific elements of the Company's proposed PBMRP, our testimony reviews: (1) the Revenue Cap Formula (I-X); (2) the Consumer Dividend that ensures customers share in efficiency gains; (3) the earnings sharing mechanism; (4) the exogenous factor (Z-Factor); and (5) the proposed capital funding mechanism, along with the proposed review schedule and annual reporting requirement. Lastly, we cover the performance metrics that the Company has developed to promote customer benefits, operational efficiency and regulatory accountability.

2. Revenue Cap Formula (I-X)

Q. What is the revenue-cap formula and how was it developed?

A. The PBR partial revenue cap formula is based on an economic analysis of utility cost trends as measured by inflation, input prices and total factor productivity. The specific revenue-cap formula proposed by the Company is discussed in the testimony of Julia Frayer of London Economics International, LLC ("LEI"). Ms. Frayer has performed in-depth economic research and analysis supporting the Company's proposed revenue-cap formula and her testimony details the methodological underpinnings of that formula.

Ms. Frayer's testimony explains that LEI's industry Total Factor Productivity ("TFP") study measures productivity growth using both capital and O&M inputs to evaluate overall industry productivity. The study also produces partial factor productivity ("PFP") measures for capital and O&M individually. PFP measures the productivity of a single input by comparing the growth in utility output to the growth in that input.

Because CL&P's proposed revenue adjustment mechanism applies only to OM&A costs, the relevant measure of industry productivity is the O&M PFP. The O&M PFP measures changes in operating efficiency over to time by comparing customer growth to the growth in inflation-adjusted O&M inputs, where O&M expenditures are converted into input quantities using a customized input price index that reflects both labor costs and non-labor costs. Accordingly, the OM&A PFP measures changes in

the quantity of operating resources used to serve customers, independent of changes in input prices.

Ms. Frayer's industry TFP study estimated an average annual O&M PFP growth rate of -0.03% over the 2005-2024 study period for the US electric distribution industry, and this value serves as the basis for the Company's proposed X-Factor. Unlike a traditional I-X framework that relies on an economy-wide inflation index and therefore requires adjustments for productivity and input price differentials, CL&P's proposed I-Factor is based on a composite O&M input price index consisting of the Employment Cost Index ("ECI") and Gross Domestic Product Price Index ("GDP-PI"), weighted using the industry's labor and non-labor OM&A cost shares. Because the proposed I-Factor reflects the same O&M cost structure measured by the O&M PFP, no further adjustments are required to convert the O&M PFP into the proposed X-Factor.

Q. Why is the X factor negative?

A. A negative O&M PFP indicates that, over the 20-year study period, the quantity of O&M inputs grew slightly faster than the quantity of outputs. In LEI's Industry TFP Study, output is measured by the number of customers served, while O&M inputs represent the inflation-adjusted quantity of operations, maintenance, customer service, customer account, sales, and allocated administrative and general costs used to provide electric distribution service. Over the 2005-2024 period, the number of customers served increased by an average of approximately 0.78% per year, while O&M inputs

increased by approximately 2.19% per year, resulting in an average O&M PFP growth rate of -0.03% per year.

Q. Is the Company requesting that PURA adopt the negative X-Factor value derived through the economic analysis performed by Ms. Frayer?

A. Yes, the Company is proposing that PURA adopt a negative X-Factor of 0.03 percent as the basis for the annual revenue adjustment in the PBMRP formula. As demonstrated in Ms. Frayer's analysis, the Company and industry as a whole is experiencing upward pressure on its O&M costs, especially during the last few years. Accordingly, the Company is proposing an X-Factor grounded in objective data and analysis that accurately reflects those cost pressures.

Q. How would the Company compute the inflation index for each annual filing?

A. As discussed above, the Company's proposed X-Factor is based on an O&M partial factor productivity measure. Accordingly, the corresponding I-Factor should reflect changes in the prices of the O&M costs whose productivity is being measured—namely, labor and non-labor costs. Using an input price index that aligns with the underlying productivity measure is consistent with the economic principles of an I-X revenue adjustment mechanism. This approach enables the I Factor to reflect changes in input prices, while the X-Factor captures expected OM&A productivity improvements.

To achieve this objective, CL&P proposes a composite O&M input price index that combines the ECI for utilities industry labor costs and the GDP-PI for non-labor

operating costs. The two indices would be weighted according to the electric distribution industry's 20-year historical shares of labor and non-labor O&M costs. The ECI, published by the U.S. Bureau of Labor Statistics, is a widely recognized measure of changes in employee compensation and is well-suited for tracking labor cost inflation. Given that labor is a major component of O&M costs for electric distribution utilities, the ECI reliably indicates changes in labor expenses over time. Similarly, the GDP-PI, published by the U.S. Bureau of Economic Analysis, is a broad gauge of economy-wide price inflation. Unlike consumer price indices that focus on household purchase prices, the GDP-PI measures price movements across the entire economy, including goods and services purchased by businesses. Therefore, it serves as an appropriate proxy for inflation affecting the wide range of non-labor operating costs incurred by EDCs.

The proposed composite index appropriately reflects the inflationary pressures affecting the Company's O&M inputs and aligns with the use of an O&M-based productivity measure for the X Factor. As part of the composite inflation measure, the Company proposes a floor of 0 percent (meaning that the "I" factor cannot go negative), and a cap on the composite I factor of 5 percent.

Q. Is the Company proposing to establish a floor for inflation in the PBMRP mechanism?

A. Yes. Although negative inflation is unlikely, if inflation is negative in a single year, the Company proposes to set the "I" to zero. Because the purpose of the PBMRP is to

provide revenue support, PURA must establish a zero percent inflation floor. Otherwise, the Company would be penalized in relation to the revenue support, contrary to what the PBMRP mechanism is supposed to provide, and that would otherwise be provided under traditional cost of service ratemaking without the same performance commitments. Similarly, the Company is proposing to implement an inflation cap of five percent, such that the I factor in the I-X formula would not be greater than five percent. The Company proposes to implement this cap as a means to reasonably limit the magnitude of adjustments between base rate cases.

3. Consumer Dividend (S-Factor)

Q. Please provide an overview of the Company's proposed Consumer Dividend.

A. The proposed Consumer Dividend measures CL&P's core operating and maintenance costs per customer against an inflation-adjusted benchmark. If the Company outperforms this benchmark -- achieving higher-than-expected operating efficiency -- customers receive a dividend funded by investors. This ensures customers share directly in the benefits of the Company's efficiency improvements.

Importantly, the Consumer Dividend is designed exclusively for customer benefit. It would be set initially at 30 basis points and would not be allowed to decrease lower than that level. The Company is proposing to increase the dividend when the Company achieves efficiencies, and that customers receive this benefit regardless of whether excess earnings are available for sharing.

Thus, the Consumer Dividend naturally complements the proposed PBMRP framework. Performance-based regulation incentivizes operating efficiencies, while the Consumer Dividend offers a direct and transparent way for customers to share in the resulting value. Together, these features ensure that the benefits of improved utility performance are not only realized but also meaningfully shared with customers.

Q. How is the Consumer Dividend funded?

A. The Consumer Dividend is funded by reducing the revenue the Company would otherwise collect through the PBMRP annual adjustment mechanism. Instead of appearing as a separate charge or rider on customer bills, it is applied as a reduction to the annual adjustment before revenues are collected. This approach allows customers to directly share in the operating efficiencies realized by the Company.

Importantly, the Consumer Dividend is designed to always be a credit, or a deduct from the calculation. Here, the Company is proposing to adjust the Consumer Dividend based on performance as described below, except that it can never go below 30 basis points, and that it will be capped in order to ensure it does not exceed the applicable inflation factor for the year. Since it reduces revenue before collection, rather than deferring costs for future recovery, no regulatory asset or reserve is created, and no carrying charges or interest apply.

Q. How is the Consumer Dividend determined?

A. The Consumer Dividend is set each year by comparing the Company's "Core Operating Expense" per customer to an inflation-adjusted benchmark. If the Company's actual O&M per customer in the year prior to the PBR rate year is below this benchmark, showing that operating costs have risen by less than the allowed inflation adjustment, the Consumer Dividend will increase by 10 basis points in the upcoming applicable PBR adjustment. If actual costs meet or exceed the benchmark, the Consumer Dividend will decrease by five basis points and will never go below 30 basis points in total. This metric measures operating efficiency, not earnings or financial performance.

Q. How is the benchmark established?

A. The benchmark is expressed on a per-customer basis and set according to a fixed formula within the proposed PBMRP. In the first year of the PBMRP term, the benchmark equals the approved "Core Operating Expense" amount per customer. For each subsequent year, the benchmark is increased by the annual adjustment factor, calculated as inflation minus the productivity offset. For purposes of this benchmark the Company will use the same composite inflation factor as being a composite rate consisting of ECI and GDP-PI.

The Company's actual "Core Operating Expense" per customer is compared to the benchmark each year. Since the benchmark is based on the "Base-Rate O&M" per customer and increases only under the established escalation formula, strong

performance in one year does not raise the benchmark or make future years harder to achieve.

Q. Why is the Company proposing to use customer count in the benchmark rather than load?

A. Measuring O&M on a per-customer basis accounts for customer growth and focuses on changes in operating efficiency rather than system size. Using customer count rather than energy sales or load also avoids weather- and economy-driven fluctuations in the metric. Since electric load varies with weather and economic conditions, a load-based approach would require complex normalization.

Q. What is included in "Core Operating Expense"?

A. "Core Operating Expense" includes the Company's non-tracked line-of-business operating and maintenance expenses, along with O&M costs recovered through the existing capital recovery mechanism. "Core Operating Expense" excludes expenses that are recovered separately or are not reasonably subject to annual management control, such as vegetation management, major storm costs, and pension expense. The Company refers to this measure as "Core Operating Expense" because it is defined objectively by the expenses included in the calculation, providing a consistent and transparent metric throughout the plan term.

Q. Please describe the ratcheting mechanism that is incorporated into the design of the Consumer Dividend.

A. The Consumer Dividend uses a ratcheting mechanism to adjust the dividend level in incremental steps, depending on annual performance compared to the benchmark. The Dividend starts at a defined level and each year the Company surpasses the benchmark through increased efficiency, the Dividend rises by a set increment. If the benchmark is not met, the Dividend is reduced by half that amount.

The Consumer Dividend has a floor of 30 basis points and is capped only to the extent that it cannot exceed the composite measure of inflation in a given year, ensuring it remains a modest part of the total revenue requirement. Adjustments accumulate over the plan term, so sustained strong performance yields enduring customer benefits instead of resetting each year. At the end of the plan term, the Consumer Dividend is reset when new base rates are established in the next general rate proceeding.

Q. Why is the ratchet asymmetric and weighted in favor of customers?

A. The dividend ratchet is intentionally asymmetric for two reasons. First, the Consumer Dividend is designed as a customer affordability measure. Accordingly, when the Company achieves operating efficiencies, the mechanism is designed to provide greater benefit to customers.

Second, the smaller ½ downward adjustment serves as a stabilizing mechanism. A single year of weaker performance does not erase customer benefits from prior years;

therefore, the adjustment preserves continuity while maintaining incentives for continued efficiency improvements.

The asymmetrical design also limits the magnitude of annual changes, helping ensure that the Consumer Dividend remains appropriately sized relative to the overall PBMRP framework. Because the reduction for underperformance is smaller than the increase for successful performance, achieving operating efficiencies is the more favorable financial outcome for the Company.

Q. How was the initial Consumer Dividend established?

A. The initial Consumer Dividend is based on the Company's benchmarking analysis. The independent unit-cost and econometric studies show that the Company's operating and maintenance costs are about 26 percent higher than the modeled benchmark. Applying this analysis to the Consumer Dividend framework results in a proposed initial dividend of roughly 30 basis points.

Accordingly, the initial Consumer Dividend represents a meaningful but achievable performance target that aligns customer sharing with the efficiency opportunity identified through the benchmarking analysis.

4. <u>Earnings Sharing Mechanism</u>

Q. How is CL&P's current Earnings Sharing Mechanism structured?

A. Under the Settlement Agreement in Docket No. 17-10-46, PURA approved an earnings sharing mechanism where any annual earnings exceeding Eversource's authorized

ROE are split equally between customers and the Company. The customer portion is first applied to reduce the environmental remediation deferral. After this balance is eliminated, the remainder is used to offset catastrophic storm costs.

Q. Is CL&P proposing to include an Earnings Sharing Mechanism as part of its PBMRP plan?

A. Yes. An earnings sharing mechanism is a necessary guardrail within the context of the PBR mechanism. Under economic theory, the implementation of an earnings sharing mechanism is viewed as counteracting the cost-efficiency incentives inherent within a performance plan by sharing the cost savings with customers rather than allowing the Company to retain the "fruits of its labor," as economic theory would suggest. However, as part of the Company's commitment to a PBMRP that provides benefits to customers, the Company proposes that, consistent with current practice, any earnings above the Company's authorized ROE in this proceeding would be shared on a 50/50 basis between the Company and customers. But rather than applying the customer portion of any earnings to offset environmental remediation or storm costs, the Company proposes to pass the customer portion of any excess directly through to customers.

Q. Is the Company proposing a downside earning sharing mechanism in the event that the Company's actual return of equity is lower than the allowed ROE?

A. No, the Company proposes to assume the risk of earning a lower ROE during the four-year PBMRP term, provided the PBMRP ultimately adopted by PURA is

methodologically sound and the Company is able to commit to such a stay-out after a review of the final decision issued in this proceeding.

5. Exogenous Factor (Z-Factor)

Q. Please describe the Company's proposed criteria for the exogenous cost factor.

A. Over the course of a four-year PBMRP term, there is the possibility that events beyond the Company's control could result in a cost change of such significance that could upset the balance of the PBMRP. For this reason, a common guardrail established for PBR plans is an "exogenous cost" or Z-Factor.

For purposes of the PBMRP mechanism, "exogenous costs" are defined as positive or negative cost changes that are beyond the Company's control and not reflected in the calculation of the I factor. The Company would include any request for exogenous cost recovery in its annual PBMRP compliance filing.

The following are examples of events that would qualify for recovery as an Exogenous Event (whether positive or negative): (1) State Initiated Cost Change; (2) Federally Initiated Cost Change; (3) Regulatory Cost Reassignment; or (4) Externally Imposed Accounting Rule Change. The preceding list is not comprehensive but provides examples of events outside the Company's control. With the occurrence of a qualifying Exogenous Event, the Company would be allowed to adjust distribution rates upward or downward (to the extent that the revenue impact of such event is not otherwise captured through another rate mechanism that has been approved by PURA) if the total

distribution revenue impact (positive or negative) of all such events meets or exceeds a threshold significance of 0.5 percent of CL&P's total distribution revenue. Currently that would be a significance threshold of approximately $10 million (i.e., 0.5% x $2 billion)[13].

The proposed formula for calculating the significance threshold provides consistency and comparability between utilities and between disparate exogenous events, and, by establishing the threshold based on distribution revenues, it would establish a direct relationship between the exogenous event and the size of the utility to ensure the exogenous event is of a level of materiality as to warrant recovery or credit through a Z factor.

If the significance threshold is reached, the Company would qualify for recovery of the quantified, qualifying costs without deducting any amounts below the threshold. Exogenous event costs can be ongoing or discreet and non-recurring. The Company proposes to reflect ongoing exogenous event costs as a change in base distribution rates and non-recurring exogenous costs collected through a separate, reconciling factor or as an amortized expense.

[13] The Company's proposed rate year revenues total $1,921,923,000 (see Schedule C-1.0). Multiplying those revenues by a significance threshold of 0.5 percent would result in a significance threshold of $9,609,615 or approximately $10 million.

6. Capital Support Mechanism

Q. Please describe the Company's proposed capital support mechanism.

A. The Company proposes a capital support mechanism (or "F" factor in the formula) based on a fixed annual capital investment level for each year of the PBMRP, with reconciliation through PURA's annual RAM proceedings. The fixed, annual investment level will be set at the Company's capital forecast, as approved in this proceeding. As described previously, the Company has presented different investment trajectories in the Company's 5-Year TSP and is proposing to establish the capital support mechanism of the PBR adjustment consistent with the annual capital funding requirements presented in Figure 7 of this testimony.

As part of the Company's annual RAM compliance filing, actual plant additions placed in service during the applicable plan year will be reconciled against the approved forecast. Following PURA's determination that the Company's actual plant additions are prudent, used, and useful, the Company's allowed rate base and associated revenue requirement for that year will be limited to the lesser of:

1. The total revenue requirement for the forecasted capital approved in this proceeding; or
2. The total revenue requirement for the actual plant in service.

If the Company's actual capital spending exceeds the forecasted amount approved in this proceeding, the Company will not be permitted to seek recovery of the incremental investment during the initial four-year PBMRP Term. Any such investment would

instead remain subject to review and consideration in a subsequent base rate proceeding or successor PBMRP Term.

This Company's proposed capital funding mechanism sets a defined cap on capital recovery during the plan term, providing customers with greater rate certainty and placing the risk of excess capital spending on the Company. The annual reconciliation further protects customers by blocking recovery of investments that are delayed, deferred, canceled, or not placed in service, since those costs would not be reflected in the F factor, which is based on plant in service. For these reasons, the proposal aligns cost recovery with prudent investment, promotes accurate capital forecasting, and incentivizes efficient execution of the capital program, all while preventing customer over-collection.

Q. Does the Company's current capital forecast as proposed in this proceeding contemplate the deployment of AMI?

A. No, the Company's current forecast of capital expenditures presented in Figure 7 of this testimony does not include the anticipated capital costs associated with an AMI deployment. If PURA were to approve an AMI deployment before or during the PBMRP term, the Company would need to increase the forecasted budget to incorporate those investments.

Q. Does the Company propose to incorporate the anticipated capital costs of AMI into the capital budget eligible for recovery, in the event that PURA were to approve the Company's AMI deployment plan?

A. Yes, as described in the direct testimony of the Advanced Metering Infrastructure Panel, Exhibit CLP-AMI-1, CL&P proposes a cost recovery framework for AMI where AMI capital costs would be recovered through the proposed capital funding mechanism. Therefore, if PURA were to approve an AMI deployment before or during the PBMRP term, the Company would adjust the forecasted budget caps to incorporate the AMI investments.

7. Performance Incentive Metrics

Q. The Company is proposing to institute new performance metrics as part of its PBMRP. Would you please elaborate on those metrics?

A. Yes. The Company is proposing a total of 16 performance metrics designed to measure its performance in three key areas over the PBMRP term. Please refer to Exhibit CLP-ELP-3 for a performance metric summary table, that includes descriptions of the metrics, targets, and PIM design.

Table 2: Proposed PBR Metrics, By Category

System and Customer Reliability	Customer Satisfaction and Engagement	Sustainability and Financial Efficiency

• Blue Sky SAIDI (PIM)
• Blue Sky SAIFI (PIM)
• Count of Repeat CEMI-5/CELID-6 (PIM)
	• Customer PIM Suite with five components:
	  ○ Level 1 DER Interconnection Processing
	  ○ Digital Customer Engagement
		• Receivables over 60 Days as a Percentage of Revenue on a Rolling 12-Month Basis (*Reporting Only*)
		• Seven GHG Emissions (*Reporting Only*)

System and Customer Reliability	Customer Satisfaction and Engagement	Sustainability and Financial Efficiency
	○ Controllable Average Call Handle Time ○ Post Transaction Survey - CSR ○ Average Discount Rate Enrollment Time	• Four Cost Efficiency (*Reporting Only*)

Q. Please explain the purpose of the proposed performance metrics.

A. If the proposed PBMRP is approved, the Company proposes to implement numerous individual metrics within certain performance categories to provide transparency regarding the Company's performance, allowing PURA and other stakeholders to gauge the Company's progress on its PBMRP commitments. The metrics are designed with the specific intention to yield information and insight into the Company's activities and progress in specified areas of interest.

The Company is proposing a set of service quality and reliability PIMs designed to ensure that the Company maintains its high service quality standards during the PBMRP term and encourage the Company to invest in a manner that cost efficiently benefits customers through improved reliability and resiliency. The Company's proposed SAIDI and SAIFI PIMs include targets that, if not achieved, will result in penalties assessed against the Company and distributed to customers as a credit in the subsequent year. In addition, the Company proposes a Customer PIM Suite to assess customer satisfaction and engagement using an array of metrics to ensure the Company maintains a high level of customer service during the PBMRP term. The Company's

proposed Customer PIM Suite includes a composite target that, if not achieved, will result in penalties being assessed to the Company.

Q. How do performance metrics complement and support the Company's PBMRP?

A. Incentive regulation can play an important role in aligning a utility's operations with the broader goals of the state of Connecticut, and the needs of customers at large. The region is experiencing an emerging retail energy environment that depends on a reliable, modernized grid that can be increasingly complex and at times unpredictable. The Company must meet these technical challenges while also rising to the evolving needs and preferences of its customers. The proposed performance metrics are a critical tool for promoting the Company's focus on contribution to the realization of energy goals. This will create greater alignment between the Company's business objectives and regional and state priorities as well as customer expectations.

The implementation of meaningful performance metrics simply furthers the transparency and effectiveness of the PBMRP. A well-designed performance metric encourages improvements in areas that the Company may not otherwise directly pursue unless necessary to fulfill its basic obligation of safe and reliable service. PBMRP metrics incentivize the Company to achieve specific goals that go above and beyond the efficient delivery of core business operations. The Company is proud of its ongoing, rigorous efforts to ensure the delivery of reliable, resilient electric service. Therefore, the Company recognizes the importance of implementing metrics to

demonstrate performance improvements over the term of its PBMRP and has worked diligently to propose metrics that will meet this objective.

Q. Please provide an overview of the System and Customer Reliability PIMs proposed by the Company.

A. As shown in the table below, the Company is proposing three PIMs, as part of the PBMRP, that reflect service quality and reliability that connect utility financial rewards or penalties to specific, measurable performance goals. The Company is proposing two categories of PIMs focused on reliability performance from a system and customer perspective. The System Reliability PIMs, SAIDI and SAIFI, measure the Company's system-wide reliability in terms of service interruptions and the frequency of interruptions experienced by all customers during blue sky days. These industry-standard metrics provide a proven, reliable means to assess the Company's overall reliability performance. The Customer Reliability PIM, which measures the number of repeat CEMI-5 and CELID-6 customers, focuses on reliability from customer-centric perspective and seeks to assess whether specific customers are experiencing multiple service interruptions or prolonged service interruptions in consecutive years.

Table 3: Service Quality and Reliability Metrics

Metric	Description	Target	PIM
Blue Sky SAIDI	• Measures average number of minutes of interruption experienced by all customers. • SAIDI performance reflects combined impact of the frequency of interruptions and their duration. • Methodology is IEEE, excluding planned outages and major storms.	One standard deviation above 5-year fixed average 2022-2026	Sliding scale penalty only, starting at one standard deviation and capped at two standard deviations. Penalty range: $1.75 million to $3.5 million
Blue Sky SAIFI	• Measures overall frequency of interruptions experienced by average customer. • Methodology is IEEE excluding planned outages and major storms.	One standard deviation above 5-year fixed average 2022-2026	Sliding scale penalty only, starting at one standard deviation and capped at two standard deviations. Penalty range: $1.75 million to $3.5 million

Metric	Description	Target	PIM
Average Count of Repeat CEMI-5/CELID-6 Customers PIM	• Measures the combined number of repeat customers for both CEMI-5 and CELID-6. • Methodology for calculating CEMI-5 and CELID-6 is IEEE excluding planned outages, major storms, and service outages. • PIM is calculated as a composite of the number of repeat CEMI-5 and CELID-6 customers, defined as customers who have experienced 5 or more sustained interruptions, or interruptions 6 or more hours in duration, in two consecutive years.	Composite average number of repeat CEMI-5 and CELID-6 customers based on five-year fixed average 2022-2026	Sliding scale incentive only, starting at target and capped at one standard deviation. Incentive range: $750,000 to $1.5 million

The Company's proposed System and Customer Reliability PIMs are discussed in more detail in Exhibit CLP-TSP-1.

Q. Please provide an overview of the Customer PIM Suite proposed by the Company.

A. As shown in the table below, the Company is proposing five customer-centric metric performance measures that will be tracked as a suite rather than individual metrics. Penalties and incentives will be based on a composite score for all components as explained in Exhibit CLP-CUSTOMER-1.

Table 4: Customer PIM Suite Components

Metric	Description	Target
Level 1 DER Interconnection Processing	• Measures average number of business days for Eversource to process DER interconnection applications specific to key Pre-Construction and Post-Construction steps within the EDCs' direct control: Application Receipt to Conditional Approval & Municipal Inspection to Permission to Operate.	35 Average Business Days
Digital Customer Engagement	• Measures digital transactions as a percentage of overall customer transactions. • Digital transactions include engagement with customers via self-service and alert notifications.	92.18 percent (2025 Actual performance)

Metric	Description	Target
Controllable Average Call Handle Time	• Measures average amount of non-phone time associated with customer interactions by combining customer hold time and post-call work time. • Quantify operational efficiencies that impact the customer wait experience and agent capacity utilization, while excluding talk time to avoid incentivizing rushed or lower-quality customer interactions.	76 seconds (5-year historic average excluding 2024)
Post Transaction Survey – CSR	• Measures the average of four customer service representative rated attribute scores related to (1) courtesy, (2) friendliness, (3) knowledge and (4) concern measured in the Post-interaction Survey on non-credit calls. Survey metrics are measured on a 10-point scale.	8.43 (2025 Actual Survey Score)
Avg Discount Rate Enrollment Time	• Measures average number of business days it takes the Company to enroll an eligible customer in the Discount Rate following the date customer provides qualifying proof of eligibility. • The metric focuses on applications that are manually processed and meet established eligibility criteria and excludes enrollments through Community Action Agencies or Department of Social Services data matching processes.	2 Business Days

The Company's proposed Customer PIM Suite is discussed in more detail in Exhibit CLP-CUSTOMER-1.

Q. Please describe the PIM structure for the Customer PIM Suite.

A. As explained in more detail in Exhibit CLP-CUSTOMER-1, the Company proposes that the PIM for the suite of customer satisfaction and engagement metrics include a sliding scale penalty and incentive mechanism based on performance against a composite index target.

The Customer PIM Suite is comprised of five components. The Company's performance for each of the five components will be evaluated against its respective component target and then aggregated to form a composite index score. The index score enables comparison of performance and aggregation across the five metric components, each with different target units and directional performance standards.

To determine whether the Company will be assessed a penalty or receive an incentive, the Company will calculate a Composite Index that reflects performance for the entire Customer PIM Suite. The Composite Index will be determined by dividing the sum of all the component index scores by five (the number of components). Under the proposed sliding scale, a penalty will be triggered if the Composite Index is at or below 90. The Company proposes that penalties start at 40% of the maximum penalty for the Customer PIM Suite (i.e., $1.2 million) if the Company achieves a Composite Index of 90. The penalty will increase by $360,000 for each additional point below 90 (e.g., if the Composite Index is 88, the penalty will be $1.92 million). The maximum penalty of $3 million will be triggered if the Composite Index is at or below 85.

Similarly, an incentive will be triggered if the Composite Index is at or above 110. The Company proposes that the incentive level starts at 40% of the maximum possible incentive for the Customer PIM Suite (i.e., $800,000) if the Company achieves a Composite Index of 110. The incentive will increase by $240,000 for each additional point above 110, up to a maximum incentive of $2 million for a Composite Index of 115 or higher.

Q. Please provide an overview of the Sustainability and Financial Efficiency metrics proposed by the Company.

A. As shown in the table below, the Company is proposing three categories of reporting-only metrics focused on sustainability and financial efficiency.

Table 5: Sustainability and Financial Efficiency Metrics

Metric	Description
Receivables Over 60 Days as a Percentage of Revenue on a Rolling 12-Month Basis	Measures the dollar amount of active receivables greater than 60 days past due, expressed as a percentage of billed revenue over a rolling 12-month period. This metric serves as an indicator of collection performance and provides transparency into arrears trends, effectiveness of collection activities, and potential write-off exposure.
Cost Efficiency Metrics	This category includes four reporting metrics: o Core Operating Expense per Customer o Core Operating Expense per Line Mile o Capital Expense per Customer o Capital Expense per Line Mile

Metric	Description
GHG Emission Metrics	This category includes seven reporting metrics: o Total Scope 1 Emissions o Total Scope 2 Emissions o Total Scope 3 Emissions o Residential Energy Intensity (kWh sales per customer) o Commercial Energy Intensity (kWh sales per customer) o Residential Emissions Intensity (CO2e per customer) o Commercial Emissions Intensity (CO2e per customer)

The Company's proposed Sustainability and Financial Efficiency Metrics are discussed in more detail in Exhibits CLP-ENV-1 (GHG Emissions Metrics) and CLP-CUSTOMER-1 (Receivables Over 60 Days). The Company's proposed Cost Efficiency Metrics are discussed below.

Q. Please describe the Company's proposed Cost Efficiency Metrics.

A. As listed in the above table, the Company proposes to report on four metrics to provide transparency of the Company's overall core business costs during the PBMRP term. As discussed above, one of the principal objectives of the PBMRP is to identify ways to reduce controllable costs. The proposed metrics are designed to provide some insight into the Company's overall cost efficiency in a transparent and comparable manner.

The proposed metrics reflect two primary categories of costs: (1) Core Operating Expense and (2) Capital Expense. Core Operating Expense, as discussed above in Section V.3, includes core operations and maintenance expenses that are necessary, and

primarily within the Company's control, for operations and to ensure safe and reliable service to customers. These O&M costs represent the expenses incurred to operate and maintain the Company's plant and equipment, such as distribution lines, electrical poles, substations, and other costs incurred to safely, reliably and efficiently operate, maintain, and support utility infrastructure and provide customer service. For the purpose of the reporting metric, Core Operating Expense includes the Company's non-tracked distribution line-of-business and electric system improvement operating and maintenance expenses. It excludes expenses that are recovered separately or are not reasonably subject to annual management control, such as vegetation management costs, storm costs, and pension/retirement expense. Capital Expense includes the Company's capital investment expenses as reported in the annual reporting filings pursuant to Docket No. 17-10-46.

To calculate the proposed reporting metrics, the Company will divide Core Operating Expense and Capital Expense amounts by the twelve-month average customer count, as provided in FERC Form 1, and by the number of distribution circuit miles as of December 31st each year, as reported on Form 10-K, Item 2, Properties.

Q. Could you provide additional detail on the proposed PIMs, including the penalty and incentive pool.

A. Yes. As discussed above, the Company is proposing four PIMS: two System Reliability PIMS (Blue-Sky SAIDI and Blue-Sky SAIFI) (penalty only), a Customer Reliability PIM (based on a composite of count of repeat CEMI-5 and CELID-6 customers) (incentive only), and a Customer PIM Suite (based on a composite of five metric components) (penalty and incentive). The Company is voluntarily proposing penalty-based PIMs contingent upon the approval of the proposed PBMRP.

To determine the level of penalties and incentives for each PIM, the Company proposes to establish maximum financial penalty and incentive pools and allocate a percentage of the pool to the PIMs. The penalty and incentive pools represent the total amount at risk for the PIMs. Each metric, or suite of metrics, recommended for inclusion as a PIM will be assigned a specific percentage allocation of the total penalty or incentive pools.

The Company proposes to set the maximum financial penalty pool equal to the exogenous cost threshold discussed above (i.e., $10 million). The exogenous cost threshold is intended to represent a significant level of costs to the Company compared to the Company's total distribution revenues. Setting the maximum financial penalty equal to the exogenous cost threshold ensures that the maximum penalty pool represents a significant financial risk but not an overly burdensome amount that may unnecessarily jeopardize the overall financial health of the Company.

For the maximum incentive pool, the Company proposes setting it equal to half of the exogenous cost threshold (i.e., $5 million). The asymmetrical incentive v. penalty pools is intended to provide the Company with a significant financial incentive to invest resources to exceed the thresholds for the incentive-based PIMs, but also balance the potential increase in rates to customers to fund earned incentives. The Company notes that achievement of incentives for PIMs is directly tied to improvements in customer reliability and customer service and associated funding levels within the TSP plan, ensuring that the Company's efforts provide significant benefits directly to customers in order to receive a financial incentive.

The Company proposes to allocate 35 percent of the maximum penalty pool to each of the System Reliability PIMs or 70 percent in aggregate allocated to the System Reliability PIMs (i.e., $3.5 million for Blue-Sky SAIDI and $3.5 million for Blue-Sky SAIFI) and 30 percent to the Customer PIM Suite (i.e., $3 million). The Company proposes to allocate 60 percent of the maximum incentive pool to the Customer Reliability PIM (i.e., $3 million) and 40 percent to the Customer PIM Suite (i.e., $2 million). The proposed allocations are designed to place slightly more weight on metrics related to overall service reliability and resiliency while maintaining the asymmetrical penalty v. incentive structure for the PIMs.

Each PIM is designed with a sliding scale incentive structure. Rather than receiving a full penalty or incentive when a threshold is met, penalties and incentives will be

calculated on a sliding scale, increasingly progressively based on performance beyond the threshold. The Company has proposed an initial target (or threshold) for each PIM. If the target is met, the Company will be assessed a portion of the maximum penalty or earn a portion of the maximum incentive. For the System and Customer Reliability PIMs, meeting the target is commensurate with 50 percent of the maximum incentive or penalty. For the Customer PIM Suite, meeting the composite index target is commensurate with 40 percent of the maximum incentive or penalty. The eligible penalty or incentive will increase for performance beyond the target up to an established cap, which is based on standard deviations for the System and Customer Reliability PIM and a percentage from the composite index target for the Customer PIM Suite.

Please refer to Exhibits CLP-TSP-1 and CLP-CUSTOMER-1 for more information regarding the design of the penalty and incentive mechanisms for each PIM.

Q. How will the penalties or incentives calculated under the PIM be paid to or collected from customers?

A. The Company proposes to collect earned PIM Incentives or to pay PIM penalties incurred in the prior year through a separate reconciling rate factor taking effect on July 1 each year following the performance year. The Company proposes to implement the rate adjustment commensurate with the PBR rate change, but to treat it separate from the formula (similar to one-time exogenous cost changes) rather than through a base rate change.

8. Proposed Review Schedule and Annual Reporting Requirements

Q. Please describe the Company's proposed cadence for regulatory review and annual cost documentation process.

A. The Company proposes to align the PBMRP with the Rate Year, with PBMRP adjustments occurring on July 1 each year.

For each year that the PBMRP mechanism is in effect, the Company would submit an Annual PBR Plan Compliance Filing to PURA in the annual RAM proceeding. The annual compliance filing would include, among other things: (1) the calculation of the annual revenue-cap adjustment; (2) the new proposed rate using the PBR formula; (3) an earnings-sharing computation; (4) cost documentation for the Company's capital investments; (5) the calculation and reconciliation of the annual capital-cap adjustment; (6) documentation of metric performance and resulting penalties or incentives and (7) bill impacts of the new rate by rate class. Any request for exogenous cost recovery would also be included in the annual compliance filing.

Q. Is the Company proposing an option to extend the PBMRP after the expiration of the first four-year term?

A. Yes. A fundamental precept of the PBMRP is that it is designed to provide a source of funding for the Company's operations and capital investment, while establishing rates that change over a steady trajectory, rather than triggering the need for base-rate filings that result in single, substantial rate adjustments for customers. If the PBMRP is functioning well and the proper balance between the Company's funding needs and customer affordability and rate stability is achieved, continuation of the PBMRP may

be in the best interests of all stakeholders. The Company is committed to remain under the PBMRP term for so long as the balance between the Company and customers is relatively balanced because this is the optimal solution for maintaining adequate funding of the system, with maximum rate stabilization over time.

Accordingly, the Company requests that PURA provide the opportunity to submit a request to extend the PBMRP for up to an additional four-year term in lieu of filing a new base-rate petition.

C. Additional Rate Design Tools

Q. Is the Company proposing additional rate design tools in this proceeding?

A. Yes. As discussed in Section VI below, the Company is proposing a new ratemaking paradigm for storm cost recovery. Additionally, CL&P is proposing a new heat-pump rate and an economic development rate.

As discussed in Exhibit CLP-RATES-1, the Company's proposed Economic Development Rate is designed to attract and retain new electric load that businesses might otherwise locate outside Connecticut. This rate ensures participating customers continue to contribute appropriately to the Company's fixed costs, while implementing safeguards to prevent existing customers from subsidizing new load. This proposal delivers multiple benefits. First, existing customers experience downward pressure on their share of fixed system costs because expenses are distributed across a broader customer base. Second, Connecticut gains from increased economic activity, job

creation, and capital investment. Third, utilization of the electric system increases, meaning available capacity is used more efficiently.

As discussed in Exhibit CLP-RATES-1, the Company's proposed Heat Pump Rate is similarly focused on encouraging beneficial load growth. Households converting to electric air-source heat pumps may experience higher overall heating costs, driven by current electricity rates and rate designs. Without an alternative rate offering, households are unlikely to adopt heat-pump technology at a pace and scale necessary to achieve Connecticut's net-zero greenhouse gas emissions target. The Company's heat-pump rate is designed to address this barrier—mitigating the higher electric costs associated with operation of a heat pump while remaining cost-reflective.

Q. Is the Company proposing to maintain its existing revenue decoupling mechanism?

A. Yes. Consistent with Conn. Gen. Stat. §16-19-tt(b), the Company is proposing to continue the revenue decoupling mechanism with one modification to allow for carrying charges on any over/under-recovery consistent with all other Rate Adjustment Mechanism ("RAM") components. This proposal is described in the testimony of the Rates Panel in Exhibit CLP-RATES-1.

VI. Storm Cost Recovery.

Q. Please summarize the Company's storm-cost-related proposals in this rate case.

A. The Company's storm-cost-related proposals in this proceeding are summarized as follows:

- **Catastrophic storm reserve funding:** The Company is proposing to establish the customer contribution to the catastrophic storm reserve in base rates at $60 million per year. *This amount is equal to the amount currently collected in rates*.

- **Pre-staging reserve funding:** The Company is proposing to establish a level of pre-staging reserve funding in base rates at $4 million per year.

- **Adjust threshold for catastrophic storm cost deferral treatment:** The Company is proposing to increase the threshold for catastrophic storm costs from $4 million to $5.4 million.

- **Implement a new Storm Cost Recovery Adjustment Factor ("SCRAF"):** In order to enable more timely review of storm cost documentation and to prevent large under-recoveries (or over-recoveries) of catastrophic storm costs, the Company is proposing to implement a SCRAF mechanism.

- **Establish cost recovery for previously deferred catastrophic and pre-staging storm costs:** The Company is proposing to implement the SCRAF for storm cost review and recovery going forward, and also as a factor to recover previously incurred catastrophic and pre-staging costs.

- **Establish new criteria for determination of a storm event for smaller weather systems that cause damage sufficient to exceed the cost threshold for a catastrophic storm, without a single detrimental impact.** The Company is proposing new criteria to apply when weather systems arise that

are not conventional "storms" but are impactful to the system and cause the need for external crews to restore power to customers.

- **Request recovery of carrying costs** associated with deferred storm costs from Docket No. 25-12-13, and future dockets.

Q. What is the Company's overall proposal for the recovery of incremental expense associated with catastrophic storms and pre-staging activities?

A. In this case, the Company is proposing to establish a new rate mechanism to operate outside of base rates to allow for more timely review and recovery of catastrophic storm costs than is possible under the current paradigm. Specifically, the Company is proposing to implement a Storm Cost Recovery Adjustment Factor, or "SCRAF." The SCRAF would function with the expectation of more systematic reviews of storm-cost prudence and allow for annual rate changes, when necessary, to recover catastrophic storm and pre-staging costs deemed prudent by PURA on a more programmatic basis to avoid a large pile-up, as has occurred in Connecticut to date. This would help prevent the buildup of catastrophic storm and prestaging event costs in between rate cases causing the potential for customer rate shock and additional carrying charges. The Company's proposal also addresses carrying charges on the net under or over-recovered balance should the amount in rates for catastrophic storm costs prove to be more or less than the amount of qualifying events deemed prudent by PURA and allowable for recovery. More programmatic recovery is the primary device for limiting the amount of carrying costs applicable to deferred storm costs.

Q. What costs would be recoverable through the SCRAF?

A. The costs that would be recovered through the proposed SCRAF would be those catastrophic storm and pre-staging event costs deemed prudent by PURA after the annual review process discussed further below.

Catastrophic Storm Events

Q. What is the Company's proposed definition of a catastrophic storm?

A. The Company's proposal is that catastrophic storms be defined as storms where the total incremental costs incurred are greater than $5.4 million. This threshold was calculated by escalating the current catastrophic storm threshold of $4 million using inflation factors based on GDP-PI from 2018 through the Rate Year. Once a storm crosses the $5.4 million threshold, all incremental costs would be considered as catastrophic storm costs (i.e., the total cost of the catastrophic storm would include the costs associated with any pre-staging activities and any restoration activities).[14]

Q. Is the Company proposing any additional criteria for the determination of a "storm" event?

A. Yes. It has become apparent that there is a growing mismatch between regulatory expectations for outage recovery and expectations associated with recovery of costs associated with restoration efforts not contemplated in base rates. As described in the testimony of the Revenue Requirements Panel, modulating storm costs are not included

[14] Carrying costs would not be included in determining whether a storm has exceeded the cost threshold to be considered a catastrophic storm.

in base rates because the frequency of storms and magnitude of the impact is indeterminate and, therefore, is not susceptible to recovery through base rates. Base rate recovery requires identification of a "representative" amount of cost for fair and effective recovery, which is an impossibility in relation to larger storm impacts that do not routinely or consistently occur. The costs of responding to "normally recurring" stormy weather is included in base rates on a representative basis. Therefore, the challenge is to identify an approach to differentiate between these two classifications of storm impacts. As a third component, it is necessary to account for larger, expected events that do not materialize after pre-staging efforts are completed.

Q. What about "heat events"? Does the Company anticipate that it is important to define what circumstances would constitute a "catastrophic" event, aside from the "big bang" events that are readily acknowledged to constitute a "catastrophic" event, so long as the dollar threshold is reached?

A. Yes. There is growing consistency in the peak summer conditions that constitute a "heat event". Heat events are weather systems that cause equipment failures and customer outages on the distribution system similar to other weather systems, except that the physical characteristics of the weather system are less dynamic (and therefore less obvious) to the casual observer. Like weather systems that are occasioned by high winds, rain, snow or lightning, multi-day high-heat, heavy humidity weather systems can inflict damage and create unanticipated overloads on the distribution system that drive equipment failures and associated customer outages. Because heat events are weather systems that impose stress on the system in a manner similar to other weather

systems, the cost of responding to these events needs to be eligible for recovery through the Storm Fund. As with other storm events, the Company has limited ability to mitigate or eliminate the risks posed by high-heat events ahead of the event; to avoid the impact on the distribution system; or to influence customer behaviors that simultaneously impact the system in reaction to the heat event.

There is also widespread recognition of the "heat wave" as significant storm event. For example, the Federal Emergency Management Agency ("FEMA") defines "extreme heat conditions" as two days of temperatures over 90 degrees Fahrenheit. The National Oceanic and Atmospheric Administration ("NOAA") defines a "heat wave" as a period of unusually hot weather that typically lasts two or more days. In a typical year around 1990, people in Hartford, CT experienced about 7 days above 90.9 F in a year. By 2050, people in Hartford are projected to experience an average of about 33 days per year over 90.9ºF.[15] The hottest year on record for the Hartford, CT area was 2024, which recorded an unprecedented average annual temperature of 55°F. [16] Climate change is increasing the frequency and intensity of heat waves, even in places with cooler average temperatures. PURA's standard for recovery of storm costs through the Storm Fund is that the Company must demonstrate that the costs are incremental, storm-related and were reasonably and prudently incurred. Damage to the distribution

[15] https://climatecheck.com/connecticut/hartford

[16] nbcconnecticut.com/news/national-international-news/changing-climate/changing-climate-the-impact-on-connecticuts-weather/3516230/

system associated with Heat Wave events is part of the challenge for the electric system.

Q. Why are heat waves and diffuse weather systems potentially impactful to the distribution system?

A. Higher-than-normal temperatures over a two-day or longer period associated with a heat wave causes an increase in air conditioning use, which in turn stresses the New England grid, as well as the Company's distribution system. During a heat event, the "heat island" effect ensures that temperatures remain high around the clock during the event, resulting in continuous, increased air conditioning use as customers try to cool their homes and businesses, not to mention hospitals, nursing homes, day cares, cooling centers, etc. As cities develop, vegetation is often lost, and more surfaces are paved or covered with buildings, which can lead to higher temperatures. Compared with surrounding rural areas, built-up areas have higher temperatures. Structures such as buildings, roads, and other infrastructure absorb and re-emit the sun's heat more than natural landscapes such as forests and water bodies. Urban areas, where these structures are highly concentrated and greenery is limited, become "islands" of higher temperatures relative to outlying areas. Daytime temperatures in urban areas are approximately 1–7°F higher than temperatures in outlying areas and nighttime temperatures are about 2-5°F higher.

Q. What is the impact that a heat wave has on the distribution system?

A. Equipment thermal rating is a function of a number of factors, including ambient temperature. The higher the ambient temperature, the less the electrical current that can flow though equipment without violating thermal limits. At the same time, the higher the ambient temperature, the higher the load demand (due mainly to cooling needs). The added weather phenomena of a cold front (with corresponding severe thunderstorms) moving into the territory following periods of extreme heat can further exacerbate the impacts on an already strained electrical infrastructure, as well as resulting in damage to the system through, for example, lightning strikes, tree falls on equipment due to high winds, flooding and other weather conditions.

This intersection of detrimental impacts on system equipment and the very same time demand is ramping up is most critical during a heat wave when demand is consistently high and transformers cannot cool down sufficiently. Consequently, these types of heat events compound high demand and lower thermal equipment capacity to create higher likelihood of equipment failures. For example, station transformer failure has more severe implications for system performance and replacement costs than service transformers. In addition, during heat events, it is more likely that large areas of the system, as a whole, are placed under stress conditions thereby reducing the flexibility to operate the system, which can cause longer outages during emergency conditions.

During a multi-day high-heat, heavy humidity event, equipment, cables and connections have the potential to fail, just as they do in a wind event, forcing the electric system into an operating condition above its design capacity, i.e., above the N-1 condition,[17] weather conditions, system failures are caused by the prolonged high temperatures and heavy humidity straining the system without any direct correlation to equipment loading. Among other types of damage, the prolonged period of high heat and heavy humidity can have a latent effect on insulating materials, diminishing the ability of system components to withstand the weather conditions imposed on the system.

In addition, under non-heat event conditions, when a fault occurs on the system, the problem area is isolated and, in most cases, the customer load is shifted to adjacent circuits. During multi-day heat events, the Company has a lesser degree of flexibility to transfer load due to demand on the system caused by increased load associated with air-conditioning usage and the fact that high temperatures and humidity around the clock are preventing the system equipment from cooling. This inability to shift load can lead to cascading outages. Equipment failures result in protective equipment opening to isolate the fault. Therefore, an equipment failure will show up in the Company's Outage Management Systems (OMS). During the heat event, like all storm events, the interruptions showing up in OMS are used to prioritize restoration per the

[17] The N-1 criterion is a standard used to evaluate the resilience of an electrical grid. It ensures that the system can continue to function normally even if one critical component — such as a transformer, transmission line, or generator — fails unexpectedly.

Company's ERP plan and regulatory mandates. In other words, the cause of the interruption being an equipment failure is not a basis to prioritize or deprioritize restoration.

Moreover, due to the stochastic nature of equipment failures during heat events, the Company is unable, ahead of the event, to predict which pieces of equipment will fail during the event. Given that a proactive transformer replacement program will not (and cannot) eliminate the possibility of single-unit transformer failures due to the incremental load strain arising from last-minute window AC unit installation and therefore will not substantially improve system operations during a heat event and avoid outages, the Company's sole means of proactively preparing for a heat event is to retain a large number of on-system crews through the afternoon and evening shifts to replace transformers that fail during the peak period of the day. These crews remain on stand-by, resulting in overtime, to ensure that there are adequate resources to address outages caused by transformer failures. The Company maintains the same practices with crews that work on underground circuits, particularly in urban areas where failures can result in significant customer outages. The costs to keep these crews on-system are incremental to costs recovered in rates and the costs are clearly related to preparing for and responding to failures caused by heat events, since the crews would not remain on-system but for the heat event.

Although equipment failure is driven by high temperatures, humidity and the associated increase in demand during multi-day heat events, there is nota direct correlation to equipment loading. This makes the failures impossible to predict and therefore impossible to plan for, e.g., a proactive replacement of transformers ahead of a heat event would likely do nothing to limit transformer failures during the event, which is exactly the case with tropical storms and snowstorms. There is no way for the Company to predict where, how and to what extent the system will be damaged as a result of the weather system and its particular characteristics.

A feeder failure during a multi-day high-heat, heavy humidity event results in customer outages during one of the most critical times of the year, as well as loading conditions that have the potential to create additional failures and cascade to even larger events as faulted equipment is isolated and load is shifted to adjacent circuits. Therefore, the potential for a feeder, equipment, or joint failure, particularly during a multi-day heatwave event must be addressed in expeditiously with outside crews because the system is running in an abnormal configuration (basically an N-1 condition) that, combined with smaller secondary outages and potential distribution transformer overloads, requires the Company to use crew resources above and beyond the Company's own staffing.

Multi-day high-heat and heavy humidity weather events are conditions that the Company cannot control or predict. Although the Company could add additional layers

of redundancy to reduce the severity and risk of impacts during a multi-day heatwave event, these types of steps would come at far greater cost for customers than allowing recovery of outside crew costs when these conditions do occur, particularly in light of the fact that these weather systems typically have a limited duration.

For these reasons, the Company is highly constrained in its ability to "plan" for heat events due to the indeterminable impact of customer behavior and the lack of correlation between equipment condition and loading and equipment failure, during a heat event. There is no way for the Company to "plan" for outages. Trying to plan for equipment failures during heat events is akin to trying to predict the impact of storm conditions during a specific hour one year in the future. Although the Company will always try to reduce the likelihood of equipment failure during heat events by not overloading equipment and removing poor performing assets, the fact remains that equipment failure during a heat event is randomly occurring.

Pre-Staging Events

Q. What is the Company's proposed definition of a pre-staging event?

A. The Company's proposal is that pre-staging events be defined as events in which the Company has notified PURA of its intent to pre-stage for an expected weather event, but where that event does not materialize into a catastrophic storm (i.e., total incremental costs do not exceed $5.4 million). The Company's proposal is that the pre-staging reserve fund would work exactly like the catastrophic storm reserve in that it

establishes an annual level of funding in base rates, but that level of funding *does not* serve as a cap.

The factors that existed when PURA authorized the establishment of the pre-staging reserve fund in Docket No. 14-05-06 still exist today. In its Decision dated August 1, 2012 in Docket No. 11-09-09, PURA Investigation of Public Service Companies' Response to 2011 Storms (2011 Storms Decision), PURA stated:

> In the future, CL&P should place higher priority on taking aggressive action in anticipation of such events, including pre-staging resources and making earlier attempts to acquire resources.
>
> The Authority finds that CL&P should establish a heightened state of readiness and be able to clearly document that such a state exists. In conjunction with this expectation, the Authority will order CL&P to report on actions it has taken to establish a heightened state of readiness in anticipation of a major storm including an assessment of its own lineworkers and lineworkers from sister companies and contractors. CL&P shall also state the mutual assistance organizations to which it belongs and the resources likely available from those organizations. The Authority requires that the primary emphasis of this report focus on those resources that are likely to be available during the first 48 hours of a major storm event to assist in efforts to ensure public safety. The Authority will also order the company to demonstrate its efforts to establish a heightened state of readiness.

2011 Storms Decision, p. 51.

In its investigation into the response to Storm Sandy in 2012 that was documented in the Decision dated August 21, 2013 in Docket No. 12-11-07, PURA Investigation into the Performance of Connecticut's Electric Distribution Companies and Gas Companies in Restoring Service Following Storm Sandy, PURA noted a number of actions that CL&P took to pre-stage resources, and concluded that the Company prepared

effectively for Storm Sandy, especially through procuring and pre-positioning supplemental lineworkers prior to the storm. Decision, pp. 16-19 and 54. This investigation confirmed the valuable role that pre-staging brings to major storm response.

PURA's decision in Docket No. 14-05-06 further supported the establishment of a storm pre-staging fund, stating:

> The Authority previously recognized the major benefits of pre-staging resources to storm restoration and public safety. The Authority also recognized that decisions on pre-staging must be made several days in advance of catastrophic storms, when the severity and timing of such storms may not be known; however, the PURA has encouraged the EDCs to make conservative decisions to ensure the state is adequately prepared for a catastrophic storm. **The Authority finds that since it has strongly encouraged both EDCs to take actions that will require them to incur pre-staging costs, the PURA should provide surety that the costs are recoverable to lessen any financial disincentive to take those actions**. The Authority concludes that the requested funding level of $2 million per year is reasonable given that costs were incurred in 2012 and 2013. As these are preparation costs for storms that never occur, the Authority will look for prudent decision-making in incurring these costs. Therefore, the Authority allows the Company to fund a reserve for pre-staging costs at the $2 million/year requested level. Unused amounts will not be accumulated for future years. At the end of each calendar year, unused pre-staging amounts should be transferred to the non pre-staging storm reserve. The Company shall separately account for storm reserve and pre-staging storm reserve amounts. Detailed activity in these accounts will be subject to audit and review at the Company's next rate filing or any other period deemed necessary by the Authority.

Docket No. 14-05-06 Decision, p. 92-93. Emphasis added.

Q. What are the types of costs of catastrophic storms and prestaging events that would be recoverable through the SCRAF?

A. To conduct restoration and recovery following the 2024-2025 Storm Events, Eversource incurred costs in seven major categories of cost: (1) direct labor costs; (2) materials; (3) payroll-related overheads; (4) vehicles; (5) outside contractors / vendors; (6) PCard transactions; and (7) employee expenses/other. Each of these cost categories is associated with specific functions and activities undertaken as part of the ERP to restore power and conduct recovery operations, as described further in the testimony of Christopher E. Colorio, Mark P. Baldwin, John P. Dipaola-Tromba, Leanne M. Landry, and John G. Griffin (Exhibit CLP-STORMS-1).

Q. How are catastrophic storm and pre-staging event costs currently recovered?

A. Catastrophic storm and pre-staging event costs are recovered through two avenues. First, the Company's current base distribution rates include a level of catastrophic storm and pre-staging reserve funding. The Company's current base distribution rates include $3 million annually for pre-staging events and $3 million annually for catastrophic storms. In addition to the $3 million for catastrophic storms, the Company was authorized to utilize expired storm amortizations from Docket Nos. 17-10-46 and 18-11-12 to provide additional storm reserve funding in the amount of $54.516 million for a total catastrophic storm reserve funding of $57.516 million and total reserve funding including pre-staging events of $60.516 million.

To the extent that the Company's catastrophic storm and pre-staging event reserve funding is not sufficient to fund the incurred catastrophic storms and pre-staging event costs, the costs have historically been collected in base rates after a full prudence review.

Q. How will catastrophic storm and pre-staging event costs be recovered effective July 1, 2027?

A. Consistent with the Company's current catastrophic storm and pre-staging event costs, the recovery would occur through two avenues. First, the Company is proposing to include a base level of reserve funding in base distribution rates. Please see the Company's discussion in this testimony for Schedules C-3.26 (Storms: Catastrophic Storm Reserve Accrual) and C-3.27 (Storms: Pre-Staging Reserve Accrual) explaining the Company's proposal for catastrophic storm pre-staging event reserve funding in base distribution rates. As described therein, the Company is proposing to include $60 million in base rates as a level of annual funding to the catastrophic storm reserve fund and $4 million as a level of annual funding for pre-staging events. Second, the Company is proposing to implement the SCRAF to have an annual review process that will enable PURA and other parties to more timely review the storm costs for prudence. In addition, to the extent that the catastrophic storm and pre-staging event reserve funding is different from actual experience in a given year, the Company's proposal is to implement a rate change through the SCRAF, as necessary. The Company's proposal is to enable an annual prudence review of storm cost documentation, and to

allow for a flexible approach to rate changes depending on circumstances at the time, as explained below.

Q. Would the pre-staging reserve function as a cap on recovery in a given year?

A. No. If the pre-staging reserve fund was meant to be a cap, rather than a funding reserve level, that would mean that the existence of the pre-staging reserve fund would only "lessen any financial disincentive" to pre-stage for events up until the point annually that it had incurred pre-staging costs up to the level allowed in rates. In other words, even though PURA "has strongly encouraged both EDCs to take actions that will require them to incur pre-staging costs" and, as a result concluded that it "should provide surety that the costs are recoverable to lessen any financial disincentive to take those actions", if pre-staging costs were capped annually, then the Company would have no "surety" that the costs are recoverable once the cap was hit, and then would have the financial disincentive "to make conservative decisions to ensure the state is adequately prepared for a catastrophic storm", should that storm event occur after the random point in the year when the Company had hit the pre-staging 'cap'. Therefore, it is the Company's proposal to establish the pre-staging reserve funding level at $4 million per year, and that the $4 million serve as an annual funding level to apply to the reserve fund, not that it will in any way serve as a cap on pre-staging costs annually.

Q. How will the proposed annual SCRAF process work?

A. As noted above, the Company's proposal is to implement an annual review process that would allow for the potential for rate changes between rate cases in order to avoid the

accumulation of significant balances of catastrophic storm and pre-staging costs. The Company's proposal is that each year it would file the actual storm costs incurred for the prior calendar year with all supporting documentation on September 1st. PURA would then conduct a contested proceeding to evaluate the prudence of all incremental catastrophic storm and pre-staging costs, the accumulated reserve balances and the potential need for a SCRAF rate change to begin recovery of prudently incurred costs. The Company's proposal is to implement any rate changes on September 1st of the following year, aligning with the Company's RAM Phase II rate changes on the same day[18].

Q. Over what period would the Company recover storm costs in the SCRAF?

A. The Company's proposal is to implement a flexible SCRAF that will allow the Company, and PURA, to more nimbly react to circumstances in the future. The Company is suggesting to not impose a strict period over which over or under recoveries will be collected or refunded, but rather will be based on the facts and circumstances at each particular time of the proposed rate change. The Company is proposing to allow for a range of amortizations of prudent catastrophic storm and pre-staging event costs from one to five years. This will allow PURA to evaluate the unique circumstances that are being experienced at the time of a proposed rate change to

[18] The Company notes that for the first year's filing it would evaluate all storms incurred after the storms subject to review in this docket. For example, the Company would file on September 1, 2027 for a prudence review of 2025 catastrophic storms and pre-staging events not included in this filing and all 2026 catastrophic storms and pre-staging events. The Company would change rates effective September 1, 2028 to reflect the approved rate change resulting from that docket, as applicable.

balance the interests of customers and the Company. For instance, if the deferral balance (i.e., the difference between the reserve funding balance and the balance of storm costs incurred) is relatively small, it may be preferable for PURA to collect or refund the difference over a shorter time frame to minimize the impact of carrying charges with a relatively small bill impact. Conversely, if the balance is great, it may be appropriate for a longer amortization to mitigate rate shock to customers.

Recovery of 2018-2023 catastrophic storm and pre-staging costs.

Q. Please describe the Company's proposal for recovering the costs associated with the 2018-2023 catastrophic storm and pre-staging costs.

A. The 2018-2023 catastrophic storm and pre-staging costs are currently the subject of review in Docket No. 25-12-13, for which PURA has issued a Draft Decision and is expecting to issue a Final Decision on July 29, 2026. The Company's hope and expectation is to proceed with a securitization financing application in short order after the issuance of the final decision in that proceeding and to issue the bonds in 2027. Should that happen, the costs for those events would be recovered through securitization, and therefore would not require separate rate recovery, either through base rates or through the proposed SCRAF. However, the Company cannot presuppose the outcome of either Docket No. 25-12-13, or the outcome of the securitization proceeding that will follow. If all or a portion of the costs (inclusive of carrying charges) are not securitized, the Company proposes to recover the costs through the SCRAF with rates effective commensurate with new base rates in this proceeding, or

July 1, 2027. For example, PURA's Draft Decision notes that PURA "will not consider the securitization of prospective carrying charges, as the carrying charges will be incurred after January 1, 2025" (Docket No. 25-12-13 Draft Decision at page 152) and that "[a]ccordingly, the Company may request recovery for the prospective carrying charges in Docket No. 26-05-10." (id.) If the Final Decision retains this language, the Company's proposal would be to recover the prospective carrying charges through the SCRAF. The Company has presented the revenue requirement consistent with this proposal as Exhibit CLP-REVREQ-2 (Storms A)-A,B,C,D Schedules.

Q. How has the Company incorporated carrying charges into its exhibits related to the 2018-2023 storms in this proceeding?

A. Consistent with its proposal and arguments in Docket No. 25-12-13, the Company has calculated carrying charges at the Company's WACC from the date of cost incurrence on the net storm fund balance, net of customer contributions to the storm fund that were collected during the period 2018-2023.

Q. Please describe the Company's proposal for recovering the costs associated with the 2024 and beginning of 2025 catastrophic storm and pre-staging costs.

A. In this proceeding, the Company has presented storm prudency documentation associated with 14 storms and pre-staging events that occurred during 2024 and in February and March, 2025, for a total cost of $157.270 million. The Company has offset the storm costs during that period with customer contributions to the storm fund that were collected during that same time period. The Company's proposal is to begin recovery of the net balance associated with these storm events through the SCRAF with

rates effective commensurate with new base rates in this proceeding, or July 1, 2027. The Company proposes to amortize the costs of these events over 6 years. The Company has presented the revenue requirement consistent with this proposal as Exhibit CLP-REVREQ-2 (Storms B)-A,B,C,D Schedules.

Q. How has the Company incorporated carrying charges into its exhibits related to the 2024 and beginning of 2025 in this proceeding?

A. Similar to the proposal for 2018-2023 storm costs, the Company has calculated carrying charges at the Company's WACC from the date of cost incurrence on the net storm fund balance, net of customer contributions to the storm fund that were collected during the period 2024 through March 2025.

Q. How has the Company incorporated the results of the Draft Decision issued in Docket No. 25-12-13 into its proposals in this proceeding?

A. The Company is filing its written exceptions in Docket No. 25-12-13 the same day as this rate case filing and is challenging certain aspects of the Draft Decision, including certain of the storm cost disallowances and PURA's treatment regarding carrying charges. The Company is not, however, challenging PURA's decision in the Draft Decision to apply customer contributions recovered through 2023 against the storm costs and pre-staging costs. As such, although that was not the Company's proposed use of those funds (the Company had recommended to PURA to apply customer contributions to offset storm and pre-staging costs that accumulated after 2023 in order to allow the maximum amount of costs to be securitized, given that the statute enabling securitization has both a dollar amount cap and a time boundary after which storm costs

are not allowed to be securitized) the Company has adjusted its proposals in this proceeding to reflect the customer contributions recovered between 2018-2023 against the storm and pre-staging costs that accumulated during that time period, and applied the same treatment for storm and pre-staging costs that occurred between 2024 and March, 2025. The Company has not adjusted its schedules related to 2018-2023 storm and pre-staging costs to reflect any disallowances, as those are being challenged concurrently, nor has the Company adjusted its proposal with regard to carrying charges for these storms. The Company notes that it had prepared this rate case application with the intention to apply all customer contributions against the 2024-March 2025 storms. After receiving PURA's draft Decision in Docket No. 25-12-13 on June 29, 2026, the Company adjusted its schedules as described above, to conform to the Draft Decision for the utilization of customer contributions. The timing of this change was such that the Company was able to adjust its revenue requirement calculations presented in Exhibits CLP-REVREQ-2-A,B,C,D Schedules, CLP-REVREQ-2 (Storms A)-A,B,C,D Schedules and CLP-REVREQ-2 (Storms B)-A,B,C,D Schedules. However, the Company was not able to adjust the rate exhibits to conform to this slight change in revenue requirement. Therefore, there is a small (~$1.5 million) difference between the revenue requirement presented in this proceeding and the rates that follow from the revenue requirement. This delta is immaterial and will be reconciled over the course of this proceeding as the revenue requirement is inevitably updated by the Company through the course of discovery and hearings. The

Company felt it was important to make this change so that the customer contributions were accurately reflected in the Exhibits associated with the prior storms, particularly since the Company is not challenging this aspect of the Draft Decision in its written exceptions being filed today.

Q. Will the Company incorporate the results of the Final Decision to be issued in Docket No. 25-12-13 into its proposals in this proceeding?

A. Yes. The Company is plans update its application to reflect the results of the Final Decision to be issued on July 29, 2026 in Docket No. 25-12-13. Additionally, the Company is actively monitoring Docket No. 26-04-04 for the potential securitization of storm costs approved in Docket No. 25-12-13. The Company's proposal is to utilize the first Late File interrogatory to make this update, which has been PURA's past practice for updating the cost of service to reflect changes identified as part of a rate case proceeding.

Q. What is the Company's proposal with regard to Carrying Charges in the SCRAF?

A. For the 2018-2023 storm and pre-staging costs, and the 2024-March 2025 storm and pre-staging costs, the Company is proposing to apply the carrying charges at the Company's WACC from the date of cost incurrence. As described below, the Company's cost to fund and finance the deferred storm costs is the Company's weighted average cost of capital. This is particularly true when the balance is so significant, and remains outstanding for as long as those storm costs have been without offsetting revenues to reduce or eliminate the need to finance such costs. Therefore,

the Company is proposing to apply its WACC to the net balance of under-recovered storm and pre-staging costs for the 2018-March 2025 storm costs. However, should PURA implement the SCRAF, which provides for more timely review and recovery of storm and pre-staging costs, the Company accepts the Prime rate from the date of cost incurrence, applied to the net balance of the storm fund and pre-staging reserve fund for storms occurring after March, 2025.

Recovery of the Cost to Carry and Support Deferred Assets

Q. Please provide an overview of how utilities finance their operations and capital investments.

A. Utilities finance their operations and capital investments through a combination of debt and equity capital obtained from the credit and equity markets. Lenders provide debt capital in exchange for repayment of principal and return in the form of interest, while equity investors supply capital with the expectation of earning a return based on the utility's financial performance. Because debt holders benefit from legal and structural protections (e.g., priority in bankruptcy), debt capital generally carries lower risk and therefore a lower required return. Equity investors, by contrast, have no guaranteed return and bear the residual risk of the enterprise. Therefore, their expected return must be sufficient (and greater than that of a debt investor) to compensate the equity investor for that higher level of risk.

Q. How has the Company financed the deferred storm costs associated with the 2018-March 2025 Storm Events?

A. Given the magnitude of the deferral and the duration of time over which this debt obligation of customers has remained on the Company's balance sheet, the Company has had to use a combination of long-term debt and equity to fund its day-to-day operations, including investments in the distribution system, and to cover the costs of storm events while awaiting cost recovery.

Q. Why didn't the Company finance the deferred storm costs with short-term debt?

A. Like all utilities, the Company utilizes short-term debt to provide liquidity over short time periods (i.e., less than one year), given that cash outlays exceed cash inflows from operations over those intervals. Short-term debt is used to finance day-to-day funding gaps, including ongoing construction of infrastructure, until it becomes necessary to replace it with permanent sources of capital, such as long-term debt and equity. Short-term debt instruments have caps that cannot be exceeded, such that if revenues are not sufficient to pay down the short-term debt balance before that balance approaches the cap, it must be replaced with other, longer term sources of capital. For CL&P, its short term debt limit is $600 million.

The recovery of deferred storm costs has extended for several years, and therefore, it has been financed with long-term sources of capital, long-term debt and equity. Accordingly, CL&P has employed long-term financing strategies to preserve the Company's liquidity.

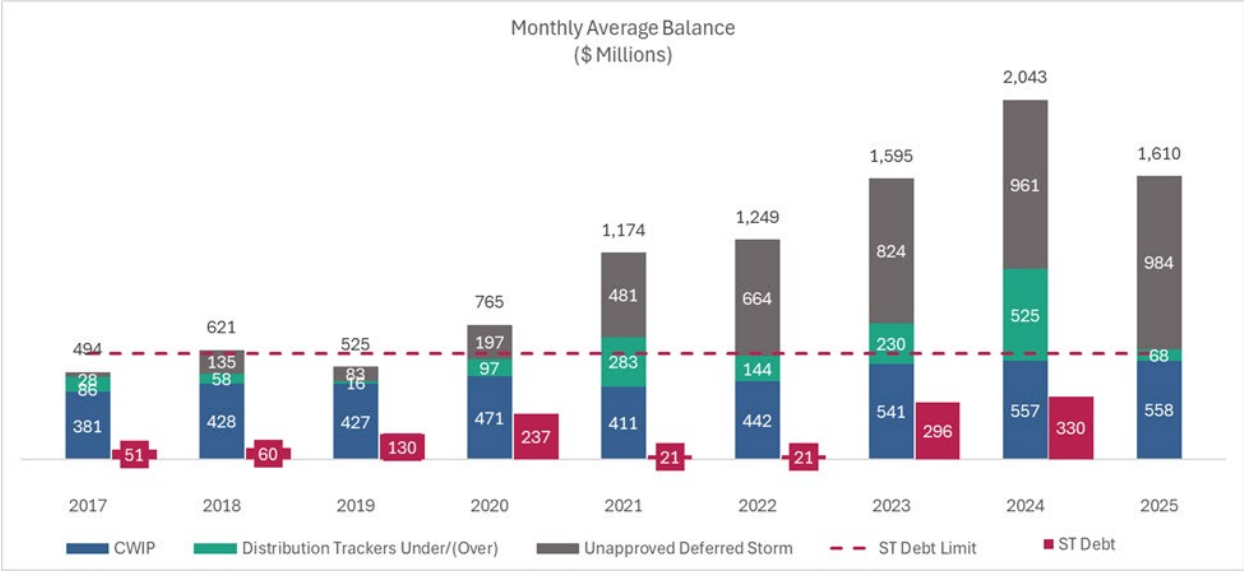
In the figure below the Company is presenting an annual comparison of (1) its short term debt capacity, (2) its actual short term debt balance, and (3) the comparable balance of notable uses of cash, including (i) Construction Work In Progress ("CWIP"), (ii) under-recoveries associated with distribution cost reconciling mechanisms, which have caused significant annual under-recoveries, requiring substantial use of Company financing since PURA changed its RAM ratemaking practice, and (iii) the increasing balance of storm costs. The figure below shows that the combined total average monthly balance of CWIP, under- or over-recovery of annual distribution rate reconciliation mechanisms, and unapproved deferred storm costs (net of funding) has greatly exceeded the short-term debt balance the Company has carried over the last nine years. Beginning with 2017, the combined net balance of these assets, has grown from approximately $494 million to more than $2 billion in 2024 before dropping down to $1.6 billion in 2025. These assets totaled more than $1.1 billion on average each month over that time frame. CWIP alone averaged $468 million per month. In contrast, the Company has carried an average short-term debt balance of approximately $123 million per month, ranging from zero to $330 million each year. FERC Order 561 clearly requires that utilities fund CWIP first with short-term debt before turning to any other sources of funds, in recognition of the fact that short term debt is generally utilized for short term capital needs (e.g., CWIP, or rate deferrals that are expected to turn around in a relatively short time frame). As depicted in the chart below, the Company's average monthly CWIP balance has significantly exceeded the average short-term debt

balance in each year 2017-2025. Therefore, it is evident that the Company's short-term debt has been utilized to fund other requirements and not utilized to finance deferred storm costs that have been outstanding and growing since 2018.

Furthermore, beginning with 2017, the Company's annual distribution rate reconciliation mechanisms have been under-recovered $167 million, on average, peaking at more than a half billion on average per month in 2024. Alongside the Company's average monthly short-term debt balance of $123 million, it is clear here as well that the Company's use of short-term debt does not cover the balance of these assets.

Taken together, the total of CWIP and distribution tracker under-recoveries has greatly exceeded the Company's average short-term debt, let alone supporting any deferred storm costs. Finally, even if the Company had fully exhausted its short-term debt capacity at all times, which would be an irresponsible business practice, the Company could not have funded deferred storms, as the horizontal red line clearly demonstrates.

Figure 12: Monthly Average Balance



Q. Please describe the specific strategies the Company has used to finance the unrecovered storm costs.

A. On a daily basis, the Company uses cash from operations to fund working capital obligations and capital expenditures. If working capital obligations coupled with capital expenditures exceed cash from operations, the Company will bridge the gap by raising short-term debt through its intercompany revolving credit agreement with Eversource. It is important in this regard to note that CL&P's short term debt capacity is limited at $600 million, which means that the Company must manage its short term debt balance to remain under that cap. As the Company's short-term debt balance approaches its limit, short-term debt will be refinanced with long-term capital in the form of long-term debt and equity via capital contributions from Eversource. Additionally, if necessary, long-term capital may be raised in advance of refunding long-term debt maturities. For this reason, it is impossible to conclude that the

Company's storm expenses have been financed with short term debt, and furthermore it would be financially irresponsible to allow the Company's short term debt balances to approach their limits for extended periods of time, since the Company must maintain adequate levels of liquidity in order to pay for emergent cash requirements.

Q. Why is the WACC the appropriate rate for calculating carrying charges?

A. As discussed above, the Company has used long-term sources of capital, both debt and equity, to finance its operations due to the persistent cash deficits caused by the delayed recovery of storm costs. Because those capital sources are the same ones reflected in the Company's overall capital structure, the appropriate measure of carrying charges on the unrecovered amounts is the WACC. PURA has previously recognized this principle.

In Docket No. 18-11-12, PURA concluded that it was "fair and reasonable . . . to allow CL&P to calculate carrying charges on the allowed regulatory asset amount, net of the applicable deferred taxes, at the Company's allowed WACC, as of the date of this Decision." Decision, Docket No. 18-11-12, Petition of the Connecticut Light and Power Company d/b/a Eversource Energy for Approval to Recover Its 2017-2018 Catastrophic Storm Costs, at 22. PURA has also found that it "is entirely appropriate and consistent with statutory and constitutional ratemaking principles for [a utility] to receive its cost of capital in connection with making . . . large long-term expenditure[s]." Decision, August 14, 2013, Docket No. 13-01-19, Application of The

United Illuminating Company to Increase Rates and Charges, at 77. Thus, PURA precedent reflects the fundamental regulatory principle that when a utility is required to finance unrecovered costs over an extended period, it should be made whole at the average cost of capital it must deploy to finance those costs.

Q. The Company is proposing to apply the Prime Rate to the net balance of storm costs and recoveries for storms which have occurred (and will occur) after March 2025 for recovery through the SCRAF. Please elaborate.

A. When the WACC is used as the applicable carrying charge rate, it is applied to the storm cost balance net of Accumulated Deferred Income Taxes ("ADIT"). This treatment is appropriate because it is consistent with traditional rate base principles, which reflect the Company's long-term investment in assets reduced by the associated deferred tax impacts. When PURA determines a company's rate base, it determines the long-term investment base, net of accumulated depreciation, which represents amounts invested but recovered from customers through rates, and net of ADIT, which represents a temporary funding source created by the timing difference between book and tax expense. PURA then applies the company's WACC to rate base on the premise that the company has had to finance the net long-term investment base (rate base) with its weighted average cost of capital. Applying the WACC to the storm balance net of ADIT therefore aligns the carrying charge calculation with the manner in which comparable long-term assets are reflected for ratemaking purposes.

Conversely, if an alternative carrying charge rate is employed that does not reflect the Company's full WACC (such as the Prime rate) the resulting calculation would not be consistent with rate base treatment. In those circumstances, the lower carrying charge rate does not incorporate the cost of equity or the overall capital structure of the Company and therefore cannot be applied to a storm cost balance net of ADIT. As a result, when such alternative rates are used, the carrying charge must instead be applied to the gross storm cost balance, without reflecting the ADIT offsets. This is the practice of the Massachusetts Department of Public Utilities as it relates to storm cost recovery for Massachusetts EDCs, and is the Company's proposal in this proceeding for storm and pre-staging costs that occur after March 2025, recovered through the SCRAF.

Q. Why didn't the Company finance its storm costs with only debt?

A. Financing obligations of this magnitude cannot be supported exclusively through debt financing, whether short-term or long-term. Instead, the Company must prudently balance its capital requirements through a reasonable mix of both debt and equity to ensure financial stability and continued access to capital.

Table 6: Sources and Uses of Cash
($ Millions)

Line	Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
1	**Connecticut Light & Power Operating Activity**										
2	Operating Revenue, excluding earnings	2,519	2,775	2,792	3,075	3,261	4,274	4,025	4,088	4,732	31,541
3	Purchased Power, Transmission, & All Other	(1,357)	(1,936)	(1,794)	(2,003)	(1,827)	(3,033)	(2,741)	(2,644)	(2,881)	(20,215)
4	O&M	(488)	(482)	(522)	(549)	(625)	(718)	(740)	(809)	(844)	(5,777)
5	Property Taxes	(144)	(154)	(167)	(189)	(182)	(202)	(201)	(211)	(226)	(1,676)
6	Capital Investment	(824)	(864)	(917)	(833)	(790)	(876)	(1,093)	(979)	(868)	(8,043)
7	Storms (unapproved & deferred only), net funding	(31)	(105)	97	(321)	(225)	(131)	(131)	(99)	(32)	(979)
8	Distribution Trackers, (Under)/Over	6	56	(11)	(136)	(211)	360	(305)	(81)	539	216
9	Working Capital, net receipt/(payment)	(60)	49	(68)	57	15	(212)	15	(81)	(169)	(456)
10	Subtotal, Source/(Use) of Cash	(380)	(661)	(589)	(899)	(584)	(539)	(1,171)	(817)	251	(5,389)
11	Retained Earnings (i.e. reinvested equity capital)	116	312	63	383	55	235	183	173	116	1,636
12	Capital contributions from ES Parent		300	125	275	200	250	124	300		1,574
13	Short-term borrowing	(11)	(70)	64	(64)		(0)	457	(177)	(280)	(80)
14	Long-term debt issuance	525	500	500	400	425		800	650	400	4,200
15	Long-term debt maturity	(250)	(300)	(250)		(121)		(400)	(140)	(400)	(1,860)
16	Total Increase/(Decrease) in Cash	1	82	(87)	95	(25)	(54)	(8)	(10)	87	80
17	*Totals included above*										
18	Net equity capital (line 11 + line 12)	116	612	188	658	255	485	306	473	116	3,210
19	Long-term debt issuance, net maturity (line 14 + line 15	275	200	250	400	305		400	510		2,340
20	Increase/(Decrease) short-term debt (line 13)	(11)	(70)	64	(64)		(0)	457	(177)	(280)	(80)
21	Total Debt & equity capital funding	381	743	502	994	559	485	1,163	806	(164)	5,469
22									Equity % of capital		58.7%
23									Debt % of capital		42.8%

24	**Note:**	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
25	Average monthly short-term notes payable balance		51	60	130	237	21	21	296	330	
26	Ending short-term notes payable balance	80	70		64				457	280	

Table 6, above, provides the Company's sources and uses of cash over the last nine years. As Table 6 shows, the Company has invested $8 billion in electric infrastructure (line 6) and approximately $1 billion in financing catastrophic storm events, net of customer contributions (line 7) over this time frame. To support these investments, Table 6 shows that the Company has contributed $3.21 billion of equity capital (line 18), combined with $2.34 billion (net of maturities) in new long-term debt in the form of first mortgage bonds (line 19). At the same time, the Company's available short-

term debt usage (line 20) has decreased since December 31, 2016, showing that there are no short-term debt resources supporting the deferred storm costs.

Importantly, over the last nine years, the Company's use of funds has exceeded its sources of funds, excluding financing, by $5.389 billion (line 10), or by $599 million annually, on average. That is, over the last nine years, the Company has required approximately $5.4 billion of debt and equity capital to fund the gap between its uses of funds to maintain and enhance the energy grid, including responding to catastrophic weather events, and its sources of funds from customers.

The Company must, at all times, be positioned to respond to emerging circumstances affecting the energy grid. Those circumstances are oftentimes unpredictable and the cash implications of which are often immediate, requiring ample liquidity. Below are just a few examples of unexpected or unpredictable events that required CL&P's immediate access to funds, a requirement that would be jeopardized if the Company operated at or near its short-term debt capacity on a sustained basis.

- Storm Isaias: $254 million
- Storm Henri: $149 million
- April 2023 Storm restoration: $63 million
- July 2023 Storm restoration: $59 million
- April 2024 Storm restoration: $57 million
- Six months with storm restoration cost $20-49 million: $190 million
- Eleven months with storm restoration $10-20 million: $146 million
- 2021 settlement with PURA: $119 million
- COVID-19 and rate mitigation efforts: $193 million
- 2023 NBFMCC rate set artificially low: $265 million under-recovery

Additionally, certain types of costs, while generally more predictable in nature, are not consistent from one month to the next, and do not necessarily align with receipts through customer rates. Property tax, gross earnings tax, interest on first mortgage bonds, and income tax payments are but a handful of significant costs that are all paid either on a quarterly or semi-annual basis. Collectively, the unpredictability of some events combined with uneven cash payments for even expected costs necessitate cash flexibility on a daily basis. While reported financial statements are often shown over a single period of time, such as a year, and as of a point time, such as December 31, 2025, the flow of cash into and out of the Company is a daily balancing requirement. The purpose of financial reporting is intentionally summarized, simplified, and standardized to increase the likelihood that interested stakeholders correctly interpret and understand the material. Therefore, while the balance of outstanding short-term notes payable may appear on a balance sheet as a single number as of a single point in time, the reality is that short-term notes as well as the flow of cash into and out of the Company must be, and indeed is, managed daily. The Company preserves immediate liquidity by managing its short-term debt levels, thus preserving its capacity to borrow short-term funds.

Simply put – and as shown in Table 6 - the Company's uses of cash to fund its myriad financial obligations (i.e., RAM under recoveries, storm restoration activities, ongoing infrastructure system investments, etc.) exceed its sources of cash (revenues collected from customers); meaning it needs to be able to access external capital in the form of

debt and equity in order to remain solvent. Short term resources (short term debt) are used for temporary differences less than one year. Recovery extending beyond a year requires the use of permanent sources of capital; long-term debt and equity. Consequently, the Company needs to rely on permanent sources of capital, including long-term debt and equity resources, to fund this shortfall.

Q. Given that the Company has incurred, and will continue to incur, its weighted average cost of capital to finance the balance of storm costs, why is the Company proposing to apply the Prime rate to the balance of storm and pre-staging costs post-March 2025?

A. The Company recognizes that the appropriate treatment of carrying charges may vary based on the regulatory framework established within each jurisdiction. Different regulatory constructs reflect differing policy objectives and mechanisms designed to balance the Company's financing needs with customer impacts.

For example, in Massachusetts, the Department of Public Utilities has implemented a storm cost recovery mechanism very similar to the Company's proposed SCRAF that allows for more timely review and recovery of prudently incurred storm-related expenditures. Under this framework, the Company files annually for review and approval of accumulated storm costs, which are then amortized and recovered from customers over a five-year period. As part of this mechanism, the Company is permitted to apply carrying charges at the Prime rate, calculated from the date the costs are incurred (i.e., from the date invoices are paid).

This approach explicitly acknowledges that there is a real and measurable cost associated with the use of the Company's capital to finance deferred storm costs. At the same time, the use of a Prime-based carrying charge reflects a regulatory determination to balance the Company's need for timely cost recovery with consideration for customer rate impacts. Accordingly, this treatment represents a jurisdiction-specific policy choice that aligns with the underlying structure of the Massachusetts storm recovery mechanism and differs from approaches used in other jurisdictions where recovery timing, financing duration, and capital structure considerations may warrant alternative carrying charge methodologies.

As the Company noted in its response to LFE-31 in Docket No. 25-12-13, in establishing a going-forward framework for storm cost recovery, the Company agrees that it would be within PURA's discretion to strike a balance between the Company's costs of financing storm costs while ensuring that the Company is not 'profiting' on a force majeure event like a storm. This is particularly true in adopting a mechanism such as the SCRAF, which provides for timely review and cost recovery of storm costs. As such, the Company is proposing to implement the SCRAF for recovery of storm costs as described above. The Company is proposing that the Prime rate will apply to the net balance of storm and pre-staging costs (net of customer contributions through the storm and pre-staging reserves) from the date of cost incurrence through the date of recovery. This proposal would calculate carrying charges on a reciprocal basis, such that if the Company is over-recovered (meaning that contributions to the storm and pre-

staging reserve funds exceed the costs of both), the Company will provide carrying charges at the Prime rate on amounts over-recovered from customers, as well.

VII. A Balanced and Effective Plan for the Future.

Q. How do the various components of the Company's proposal work together to advance customer and public policy objectives?

A. The Company's proposals form an integrated framework that strategically balances affordability, reliability, resilience, accountability, and economic growth. While each component of the Company's plan addresses a specific objective, together they drive a cohesive strategy that both addresses current customer needs and proactively prepares the electric system for the future.

The engine that drives the Company's plan is the TSP, which emphasizes proactive replacement of aging infrastructure. By addressing asset conditions before failures occur, the Company enhances safety, reliability, and resilience while reducing costly emergency repairs and minimizing customer outages.

While the TSP acts as the engine driving the electric system forward, the PBMRP serves as the steering and control system, guiding direction and pace. The PBMRP limits spending growth with an inflation-based cap on O&M and a downward only reconciling mechanism for capital costs, incentivizes the Company to identify efficiencies, and delivers greater rate stability and predictability by enabling a more gradual and transparent cost recovery as compared to sequential base rate cases. For accountability, the PBMRP proposal also incorporates a robust set of performance

metrics, that serve as the gauges on the dashboard. These metrics provide insight into the Company's performance and demonstrate whether the plan's anticipated benefits are being realized. The Company has also proposed asymmetrical penalty and incentive structure for certain PIMs.

The Company's plan also features a four-year stay-out commitment, providing customers greater certainty by reducing the frequency of rate proceedings and establishing a stable regulatory framework for the Company to execute its plan. Extending the automobile analogy a little further, the stay-out provision represents a planned route that avoids unnecessary stops and detours.

Importantly, the Company's PBMRP allows customers to share in efficiency gains through a Consumer Dividend that increases as the Company achieves efficiencies under the plan, allowing customers to receive a direct share of the resulting savings.

The Company's proposed heat pump and economic development rates advance state policy goals by promoting affordability, supporting beneficial electrification, stimulating economic growth, and attracting or retaining businesses in Connecticut. These initiatives help customers and communities realize the advantages of a modern electric system while reinforcing Connecticut's long-term energy and economic objectives.

Collectively, the Company's proposals chart a balanced and sustainable course that ensures safe and reliable service, strengthens system resiliency, improves operational

efficiency, enhances rate predictability and stability, and creates value for customers, communities, and the state.

Q. In closing, why should PURA approve the Company's proposals in this proceeding?

A. Connecticut customers expect and deserve electric service that is safe, reliable, resilient, and affordable. Eversource recognizes the responsibility that comes with providing this essential service and remains committed to balancing affordability with the investments necessary to maintain and strengthen the electric system.

Affordability and reliability are closely connected. While infrastructure investments carry costs, failing to make them leads to greater long-term costs through outages, emergency repairs, operational inefficiencies, and infrastructure that cannot meet evolving customer and economic needs. In parallel, customers are relying on electricity more than ever before to power homes, businesses, hospitals, schools, transportation systems, and the technologies that support Connecticut's economy and quality of life.

The Company's proposals offer a responsible, sustainable path forward by supporting safe and reliable service, boosting resiliency, promoting operational efficiency, and enhancing rate stability and predictability for customers. They also demonstrate a firm commitment to accountability, innovation, and disciplined cost management, ensuring that customer dollars are invested prudently and deliver tangible value.

This proceeding is about more than just rates—it is about preparing Connecticut's electric system to meet future challenges and opportunities. Strategic investments now will help prevent higher costs down the road and ensure the state benefits from a modern, reliable, and resilient grid. Eversource remains committed to working with PURA to advance solutions that balance affordability with the long-term needs of customers and it looks forward to engaging with the Commission, PURA staff, and the other parties during this proceeding.

VIII. Overview of Company Witness Testimony

Q. Would you please provide an overview of the testimony the Company is submitting in support of its proposals?

A. Yes. In addition to this joint testimony, the Company is submitting the following testimony in support of its proposals:

Lavelle A. Freeman, David L. Gladey, Jennifer A. Schilling, Dr. Elli Ntakou and John P. DiPaola-Tromba (Exhibit CLP-TSP-1) For the Eversource Energy Service Company, Lavelle A. Freeman is Vice President, Distribution System Planning; David L. Gladey is Vice President, Distribution Engineering; Jennifer A Schilling is Vice President, Grid Modernization; Dr. Elli Ntakou is the Director of Telecommunications and Innovation Engineering; and Mr. John P. DiPaola-Tromba is Vice President of Asset Management and Process Improvement. Their joint testimony presents CL&P's Targeted System Performance Plan, covering the planning horizon for operations and investment on the Company's distribution system over the timeframe of January 1,

2027 through December 31, 2031. CL&P's State of the System report provides a foundational perspective on the 5-Year Plan, provided as Exhibit CLP-TSP-2. In addition, a detailed presentation of the 5-Year TSP Plan framework is presented as Exhibit CLP-TSP-3.

Jared A. Lawrence and Douglas P. Horton (Exhibit CLP-AMI-1): For Eversource Energy Service Company, Mr. Jared A. Lawrence is Senior Vice President of Customer Operations and Digital Strategy and Chief Customer Officer for Eversource Energy Service Company and Mr. Douglas P. Horton is Senior Vice President, Regulatory and Strategic Financial Planning. Their joint testimony presents the Company's proposals with respect to the implementation and cost recovery associated with CL&P's Advanced Metering Infrastructure program.

Julia Frayer (Exhibit CLP-PBR-1): Julia Frayer is a Managing Director at London Economics International, LLC, a Massachusetts-based consulting firm specializing in the energy, water, and other infrastructure industries. Ms. Frayer has conducted in-depth economic research and analysis supporting the Company's proposed PBMRP and her testimony discusses its methodological underpinnings.

Matthew Nelson and Michael Goldman (Exhibit CLP-IAP-1): Mr. Matthew Nelson and Mr. Michael Goldman are principals at Apex Analytics LLC, an energy services consulting firm that provides strategic input, evaluation support and research to energy industry stakeholders. Their joint testimony examines the affordability of electric-

system investment, outlines a framework for evaluating and addressing affordability concerns, and evaluates CL&P's TSP Plan.

Brendan J. O'Brien and Garrett J. Murray (Exhibit CLP-REVREQ-1): For Eversource Energy Service Company, Mr. Brendan J. O'Brien is Vice President, Distribution Rates and Revenue Requirements. Mr. Garrett J. Murray is the Director of Revenue Requirements for the Connecticut electric and gas utility companies. Their joint testimony presents the revenue-requirement analysis and revenue-deficiency calculation for CL&P.

David L. Gladey, John P. DiPaola-Tromba, Leanne M. Landry, and Jeffrey D. Turano (Exhibit CLP-ADDITIONS-1): For Eversource Energy Service Company, Mr. David L. Gladey is Vice President, Distribution Engineering; Mr. John. P. Dipaola-Tromba is Vice President of Asset Management and Process Improvement; Ms. Leanne M. Landry is the Director, Investment Planning and Mr. Jeffrey D. Turano is Manager, Budgets and Investment Planning. Their joint testimony provides an overview of the Company's capital planning and authorization processes and procedures and supports the demonstration of reasonable capital plant additions the Company has constructed since its last rate case in Docket No. 17-10-46.

John P. Dipaola-Tromba, Sean D. Redding, and Jenna Turner (Exhibit CLP-VMP-1): For the Eversource Energy Service Company, Mr. Dipaola-Tromba is Vice President of Asset Management and Process Improvement; Mr. Redding is Director,

Vegetation Management; and Ms. Turner is Manager, Vegetation Management. Their joint testimony provides an overview of the Company's vegetation management program ("VMP") and the Company's proposals for going forward modifications to the VMP.

Sasha P. Lazor, Marianne H. Eichler, and Kara A. O'Connor (Exhibit CLP-EMPLOYEE-1): For the Eversource Energy Service Company, Mr. Sasha Lazor is Vice President of Compensation, benefits Strategy and HR Operations; Ms. Marianne Eichler is Director of Human Resources Consulting; and Ms. Kara O'Connor is Director, Benefits Strategy. Their testimony presents the Company's employee compensation programs, including base and variable pay elements, and the Company's employee-benefit programs and associated costs, including healthcare expenses, pension, and retirement benefits.

Jess Cain, Jared A. Lawrence and Andrew C. Belden (Exhibit CLP-CUSTOMER-1): For Eversource Energy Service Company**,** Ms. Jess Cain is Vice President, Customer Operations and Assistance Programs; Mr. Jared A. Lawrence is Senior Vice President of Customer Operations and Digital Strategy and Chief Customer Officer; and Mr. Andrew C. Belden is Vice President, Solar Programs. Their testimony discusses the Company's customer-service philosophy, policies and organization. Their testimony also addresses customer affordability and the Company's proposals for customer performance metrics.

Marc J. Richards, Gary A. Iadarola, and Clare B. Connolly (Exhibit CLP-ENV-1): For the Eversource Energy Service Company, Mr. Richards is Vice President of Sustainability and Environmental Affairs; Mr. Iadarola is Manager of the Environmental Remediation Group, which oversees compliance, monitoring, investigation, remediation and related activities in connection with the environmental management of properties and assets of the Eversource affiliates, including CL&P; and Ms. Connolly is Director of Sustainability and Climate. Their testimony supports the Company's recovery of environmental remediation costs, including costs associated with long-term clean-ups. Their testimony also supports a proposal for performance metrics.

Ann E. Bulkley (Exhibit CLP-ROE-1): Ms. Ann E. Bulkley is a Principal at The Brattle Group. Ms. Bulkley's testimony presents evidence and provides recommendations regarding the appropriate cost of capital for CL&P.

Christopher E. Colorio, Mark P. Baldwin, John P. DiPaola-Tromba, Leanne M. Landry and John G. Griffin (Exhibit CLP-STORM-1): For CL&P, Mr. Christopher E. Colorio is Vice President of Electric System Operations. For the Eversource Energy Service Company, Mr. Mark P. Baldwin is Vice President, Emergency Preparedness; Mr. John P. DiPaola-Tromba is Vice President of Asset Management and Process Improvement; Ms. Leanne M. Landry is Director, Investment Planning; and Mr. John G. Griffin is Director of Budgets and Financial Analysis. Their testimony supports the

Company's request for recovery of storm costs incurred by the Company to restore power following 14 catastrophic weather events occurring between January 2024 and March 2025.

Ned W. Allis (Exhibit CLP-DEPRECIATION-1): Mr. Ned W. Allis is associated with Gannett Fleming Valuation and Rate Consultants, LLC, part of GFT Infrastructure, Inc. His testimony presents the depreciation study conducted for CL&P, as well as the annual depreciation rates and accruals as of December 31, 2025, along with the recommended service life and net salvage estimates.

Edward A. Davis and Kimberly R. Parsons (Exhibit CLP-RATES-1): For Eversource Energy Service Company, Mr. Edward A. Davis is Director of Rates; Ms. Kimberly Parsons is a Team Lead for Rates and Mr. DePace is a Team Lead for Rates. Their joint testimony presents the Company's proposed rate proposals, rate design, tariff changes, and associated bill impacts.

Amparo Nieto (Exhibit CLP-ACOS-1 and CLP-MCOS-1): Ms. Amparo Nieto is a Director at the Energy Practice of Berkley Research Group. Ms. Nietos' testimony presents the Company's allocated cost of service and marginal cost of service studies.

IX. Conclusion.

Q. Does this conclude your testimony?

A. Yes.