STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY

Docket No. 26-05-10

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

DIRECT TESTIMONY OF

LAVELLE A. FREEMAN, DAVID L. GLADEY, JENNIFER A. SCHILLING, DR. ELLI NTAKOU AND JOHN DIPAOLA-TROMBA

Powering Connecticut's Future
5-Year Targeted System Performance Plan

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 AND OVERVIEW 1

II. STATE OF THE CL&P DISTRIBUTION SYSTEM 20

III. INVESTMENT PLANNING APPROACH 34

IV. ROADMAP OF THE 5-YEAR TSP PLAN 39

A. New Customer Load 49

B. Peak Load/Capacity 49

C. ISO-NE Compliance 51

D. Overhead Aging Infrastructure 52

E. Distribution Right-of-Way Lines 52

F. Underground Cable & Equipment Replacement 53

G. Underground Network Automation 53

H. Direct Buried Cable Replacements 54

I. Substation Elimination 55

J. Substation Bulk and Distribution Transformers 55

K. Substation Switchgear and Circuit Breakers 56

L. Maintenance Programs 57

M. Enhanced Reliability and Resiliency 60

V. MEASURING SYSTEM PERFORMANCE AND INVESTMENT BENEFITS 72

VI. COMPLIANCE WITH PURA'S DECISION ON RELIABILITY AND RESILIENCY FRAMEWORKS.....83

VII. CONCLUSION 88

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I. Introduction and Overview

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

A. My name is Lavelle A. Freeman. My business address is 107 Selden Street, Berlin, Connecticut.

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

A. I am the Vice President, Distribution System Planning for Eversource Energy Services Company ("ESC"). ESC provides centralized services to the electric and natural gas operating subsidiaries of Eversource Energy, including The Connecticut Light and Power Company d/b/a Eversource Energy ("Eversource," "CL&P" or the "Company") and Yankee Gas Services Company d/b/a Eversource Energy, both operating in Connecticut.

Q. What are your principal responsibilities in this position?

A. As the Vice President of Distribution System Planning, I am responsible for overseeing all activities in Eversource's service areas in Connecticut, Massachusetts and New Hampshire related to: capacity expansion for bulk distribution substations and

supporting circuits, including developing ten-year load forecasts and detailed system models; performing system impact studies and developing solutions for large distributed energy resource ("DER") interconnections; assessing system reliability and resiliency performance and needs, and developing targeted plans for improvement; and integrated energy planning to safely and reliably transition customers from the gas system to the electric system.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Electrical Engineering from the University of Alabama. Subsequently, I earned a Master of Science degree in Electrical Engineering with a Power Systems concentration from the University of North Carolina at Charlotte and a Master of Science degree in Computer Engineering from North Carolina State University. I joined the Institute of Electrical and Electronics Engineers ("IEEE"), Power Engineering Society while in graduate school, was added to the ANSI C84.1 Standard Committee in 2019 and am a member of the Association of Edison Illuminating Companies (AEIC) Power Delivery Committee.

I started my power systems career as a Research & Development Engineer at ABB Corporate Research in Raleigh, North Carolina, where I devised innovative new products, algorithms, and solutions to improve the value and efficiency of transmission and distribution product offerings within ABB Power T&D Inc. Thereafter, I joined the ABB Utility Consulting group in Raleigh, North Carolina as a Senior Consulting

Engineer where I performed system studies in distribution and transmission planning for utility customers, worked with customers to implement changes, and developed and supported power-systems software applications that improved the efficiency, marketability and cost-effectiveness of the group.

From 2003 to 2013, I was a Senior Engineer and then a Principal Engineer at General Electric Energy in Schenectady, New York, where I led consulting studies in distribution planning and analysis, power systems engineering, equipment applications, smart grid initiatives, and renewables impact, and contributed to development of new products and technology for various General Electric Energy businesses. From 2013 to 2016, I was Manager of Transmission and Distribution at General Electric Energy Consulting where I directed a broad spectrum of client activities in the T&D space, with emphasis on power systems operation and planning, equipment application, renewables impact, and systems analysis. From 2016 through 2020, I was Technical Director at General Electric Energy Consulting in Schenectady, New York. In this position, I led project teams and developed business opportunities in the distribution space with emphasis on DER integration, microgrid design, grid modernization, reliability, power quality, and resiliency. From 2018 to 2019, I developed and led execution of over $5 million in distribution-related projects in New York, New Jersey, and Massachusetts. I also successfully completed four ground-breaking New York Prize Stage 2 microgrid design projects and managed a peer research consortium working extensively with distribution planners and engineers in investor-owned,

municipal and cooperative utilities across the country. In 2020, I joined Eversource as Director, Distribution System Planning and in 2025, I was promoted to my current position.

Q. Have you previously participated in proceedings before a regulatory body?

A. Yes. I have previously testified and participated in several proceedings before the Connecticut Public Utilities Regulatory Authority ("PURA"), including: Docket No. 17-12-03RE08, PURA Investigation Into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards, Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives, Docket No. 21-05-15RE02, PURA Investigation Into Performance-Based Regulation Framework, Docket No. 21-05-15RE03, PURA Investigation Into the Establishment Of Integrated Distribution System Planning Within a Performance-Based Regulation Framework, Docket No. 22-06-29RE01, PURA Investigation Into Distributed Energy Resource Interconnection Cost Allocation – Non-Residential Interconnection Upgrades, and Docket No. 22-06-05 PURA Implementation of Public Act 22-55. I have also testified before the Massachusetts Department of Public Utilities numerous times and before the New Hampshire Public Utilities Commission.

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

A. My name is David L. Gladey. My business address is 107 Selden Street, Berlin,

Connecticut.

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

A. I am the Vice President, Distribution Engineering, employed by ESC.

Q. What are your principal responsibilities in this position?

A. As Vice President, Distribution Engineering, I am responsible for the Eversource distribution engineering organization that includes design and field engineering for the overhead and underground distribution system, transmission and distribution standards, engineering controls and the single pole administrator ("SPA") process across Connecticut, New Hampshire and Massachusetts. In this role, I oversee distribution system design, regional and customer engineering, distribution system performance, capital investment planning, tri-state standards, engineering controls and third-party attachment programs. I also have responsibility for advancing system improvements, asset performance and supporting grid modernization initiatives across the Eversource service territory in Connecticut, New Hampshire and Massachusetts.

Q. Please describe your educational background and professional experience.

A. I graduated from The Pennsylvania State University in 1990 with a Bachelor of Science degree in Electrical Engineering and a specialization in power engineering. I began my professional career with Baltimore Gas & Electric at the Calvert Cliffs Nuclear Power Station, where I was responsible for protection and control and electrical system analysis, including off-site power requirements. I later joined PPL Electric Utilities

where I held design responsibilities for the Susquehanna Nuclear Generation Station and later oversaw the Transmission asset-management organization where I was responsible for the asset and system performance of the PPL transmission system. During my tenure at PPL, I also had responsibility for the Distribution Engineering and Asset Management organization, where I led the distribution engineering, project management, asset management, distribution planning, third-party attachment, protection and control testing and standards teams. I also held positions at PJM with both the Nuclear Generation owners and Transmission Owners and I am an active participant in industry organizations, where I serve as the Vice Chair of the Edison Electric Institute Distribution Asset Management Subcommittee and I am a member of the Association of Edison Illuminating Companies Power Delivery Committee. I am also a senior member of IEEE, where I have held leadership roles, including chairing a subcommittee and contributing to the development of standards related to nuclear power offsite and onsite electrical system requirements.

Q. Have you previously testified in proceedings before a regulatory body?

A. Yes. I have previously testified in proceedings before PURA, including with respect to CL&P's annual Rate Adjustment Mechanism ("RAM") proceedings. In addition, I have testified before the New Hampshire Public Utilities Commission in the 2025 rate-case proceeding for Public Service Company of New Hampshire d/b/a Eversource Energy.

Q. Ms. Schilling, please state your name and business address.

A. My name is Jennifer A. Schilling. My business address is 247 Station Drive, Westwood, Massachusetts.

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

A. I am Vice President of Grid Modernization, employed by ESC.

Q. What are your principal responsibilities in this position?

A. As Vice President of Grid Modernization, I am responsible for Eversource's grid modernization development, as well as developing strategies to increase the capacity of the Company's distribution system to optimize the integration of DERs, while improving the safety, security, reliability and cost-effectiveness of the system.

Q. Please describe your educational background and professional experience.

A. I graduated with a Bachelor of Arts degree in environmental science and political Science from Barnard College, Columbia University in 1995. In 2001, I earned a Master of Business Administration from Duke University. From 2001 to 2008, I held several positions at Reliant Energy in Houston Texas, ending my tenure in the position of Director, Corporate Strategy. In 2008, I joined the Northeast Utilities System as the Director of Business Planning for Western Massachusetts Electric Company ("WMECO"). I subsequently accepted the role of Director, Asset Management for WMECO and then Director, Distribution Engineering for Eversource, prior to assuming my current role.

Q. Have you previously testified in proceedings before a regulatory body?

A. Yes. I have previously participated in several proceedings before PURA. I recently testified in Docket No. 17-12-03RE07, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternatives. I also represented CL&P in PURA's investigation into the implementation of advanced metering infrastructure in Docket No. 17-12-03RE02, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Advanced Metering Infrastructure. I have also testified before the Massachusetts Department of Public Utilities numerous times, including in support of the Company's affiliate's grid modernization plan (D.P.U. 21-80) and electric sector modernization plan (D.P.U. 24-10).

Q. Dr. Ntakou, please state your name and business address.

A. My name is Dr. Elli Ntakou. My business address is 247 Station Drive, Westwood, Massachusetts.

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

A. I am the Director of Telecommunications and Innovation Engineering, employed by ESC.

Q. What are your principal responsibilities in this position?

A. As the Director of Telecommunications and Innovation Engineering for Eversource, I lead Eversource's digital transformation and transition to automation, optimization,

and data-based decision making. I am responsible for an enterprise-wide data foundation that supports data quality and the development of automation, analytics and learning tools. Additionally, as part of my storm duty role leading the storm data teams, I apply my optimization expertise to the development of storm tools for optimization of restoration crew procurement and routing.

Q. Please describe your educational background and professional experience.

A. I graduated from Boston University College of Engineering with a Master of Science and a PhD in Systems Engineering. Subsequently, I worked for ESAI Power LLC, leading their Northeast wholesale power market modeling efforts. From 2018 to July 2022, I was employed by Quanta Technology, in various positions, most recently as Senior Advisor. As part of my role, I advised a breadth of clients in the power sector on various topics including resilience and reliability, non-wires alternatives, storage use-cases and integration, grid modernization and scenario planning. In July 2022, I joined Eversource as the Manager of System Resilience and Reliability Planning. In that role, I was responsible for Eversource's reliability and resilience programs for its electrical infrastructure. Using my expertise in data, power systems and optimization, I led the development and maintenance of analytics and predictive models to optimize reliability and resilience programs through targeted, highly granular, and cost-effective reliability and resilience investments. These models consolidated disparate data from multiple source systems, ranked historical performance to understand underperforming parts of the distribution grid, assessed feasible mitigations, and proposed the most cost-

optimal mitigations, including regulatory considerations and predictive analytics, like climate projections. In March 2026, I was promoted to Director of Telecommunications and Data Innovation for Eversource.

Q. Have you previously participated in proceedings before a regulatory body?

A. Yes. I have previously participated in proceedings before PURA, including Docket No. 21-05-15RE02, PURA Investigation Into Performance-Based Regulation Framework. I have also testified before the Massachusetts Department of Public Utilities, including in support of the Company's affiliate's electric sector modernization plan (D.P.U. 24-10) and before the New Hampshire Public Utilities Commission.

Q. Mr. DiPaola-Tromba, please state your name, position and business address.

A. My name is John P. DiPaola-Tromba. My business address is 56 Prospect Street, Hartford, CT 06103. I am the Vice President of Asset Management and Process Improvement at Eversource Energy, and I am employed by ESC. On behalf of Eversource Energy, I am responsible for the leadership and direction of the Eversource Asset Management, Process Improvement, Work Management and Vegetation Management departments within the shared-services engineering business unit, including asset management for transmission and substation assets, transmission and substation capital project approvals, cost estimating for major projects, process

improvement, configuration management, and vegetation management.

Q. Please summarize your education and professional experience.

A. I earned a Bachelor of Science in Electrical Engineering, a Master of Engineering, and a Master of Business Administration from the University of Hartford in Hartford, Connecticut. I started with the Company in 2008 with experience in the engineering and transmission business, including transmission and substation asset management, capital program planning, engineering, cost estimating, process improvement, work management systems, compliance, and vegetation management. I have previously held several technical roles in engineering, asset management and compliance, including Engineer, Manager of Transmission Asset Management, Manager of Strategy and Performance, Manager of System Performance and Investment, and Director of Transmission Business and Quality Assurance. Prior to my employment with the Company, I held several positions in construction.

Q. Have you previously testified in a regulatory proceeding?

A. Yes. I most recently presented testimony to PURA in Docket No. 25-12-13, Application of the Connecticut Light and Power Company d/b/a Eversource Energy for Order to Securitize 2018-2023 Catastrophic Storm Costs. I also participated as a witness in Docket No. 20-08-03, Investigation into the Electric Distribution Companies

Preparation and Response to Tropical Storm Isaias.

Q. What are the roles and responsibilities that the Company's witnesses have in relation to the proposals covered in this testimony?

A. Company Witnesses Lavelle Freeman (distribution system planning) and David Gladey (distribution engineering) are the strategic and tactical leads responsible for developing, planning and executing on a system performance plan that will address capacity, reliability, resiliency and asset health needs in the near and long-term. Mr. Freeman focuses on evaluation of the state of the system out into the future, including substation planning and eliminating potential capacity bottlenecks, while Mr. Gladey focuses on distribution lines, which is the majority of the distribution budget, including focus on circuit performance and overhead and underground network infrastructure. Company Witness Jennifer Schilling heads up the Company's grid-modernization team focused on technology innovation and telecommunications engineering, including the control room of the future and the modern technologies that go into that such as the Company's plan for implementing a Distribution Management System ("DMS") and Distribution Energy Resource Management System ("DERMS"), along with the telecommunications infrastructure that follows. Company Witness Dr. Elli Ntakou works in Ms. Schilling's group and is charged with driving innovation through the adoption of analytical frameworks and information technology, including benefit-cost analyses to support distribution infrastructure investment and the adoption of artificial intelligence ("AI") technology and scaling that technology innovation with the electric engineering function. Prior to this role, Dr. Ntakou spent three years leading Reliability

and Resiliency Planning in the Distribution System Planning group. In that role she led the Company's thought process and analytical research to build the benefit-cost analysis ("BCA") required by PURA as part of its Reliability and Resiliency Framework, approved in Docket No. 17-12-03RE08. Company Witness John DiPaola-Tromba handles key aspects of the TSP Plan, including Substation Asset Health and Vegetation Management. This team has worked together to develop and present Exhibits CLP-TSP-2 and CLP-TSP-3 as the focal point for PURA's investigation of the Company's rate proposals, which are critical to support the system engineering and electric operations blueprint

Q. What is the purpose of this joint testimony?

A. The purpose of our joint testimony is to present CL&P's 5-Year Targeted System Performance Plan (the "TSP Plan" or the "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. A summary narrative of CL&P's State of the System report providing a foundational perspective on the 5-Year Plan is provided herewith as Exhibit CLP-TSP-2. In addition, a detailed presentation of the 5-Year TSP framework is presented as Exhibit CLP-TSP-3.

The Company developed the summary narrative and 5-Year TSP Plan presentation provided in Exhibits CLP-TSP-2 and CLP-TSP-3, respectively, to bring together several interrelated aspects of the Company's internal long-term planning and system-

management functions in order to facilitate PURA's review in this proceeding of where the Company is headed from an investment and operating plan perspective and why. The summary narrative and TSP Plan presentation are designed with specific consideration of assisting PURA and other participating parties and intervenors in gaining a line of sight into the Company's goals and objectives for investment and operation of CL&P's distribution system now and in the future to provide safe and reliable service to our customers.

Like other electric utilities grappling with the cascading effects of electrification trends, the proliferation of DER, historic changes in the socioeconomic landscape and consumer behaviors, as well as swiftly evolving information technology, CL&P is in uncharted territory and now facing an inflection point. This inflection point arises from the fact that CL&P's public-service obligation is driving the need to balance these objectives, with the imperative to maintain and/or improve electric system reliability, to bolster system resiliency in the face of climate change impacts, all while balancing customer expectations with affordability for electricity consumers.

Against this backdrop, the Company has been hard at work putting in place the human resources, information systems and business processes to meet the public service obligation that comes with the Company's exclusive franchise rights to deliver safe and reliable power to electric customers in Connecticut in a challenging operating environment. To that end, the 5-year TSP Plan describes the CL&P distribution system state and embodies the Company's current approach and analytical corroboration as to

maintain or improve performance with focus on six critical goals for system performance.

These critical goals are: (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;[1] (4) the system must have *resiliency* to withstand increasing 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

1 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.

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.

Thus, "the inflection point" is about instituting 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. Along with the Company's rate proposals, the Company's 5-year TSP Plan is designed to be an important step in this process.

In that regard, the Company recognizes that, without a clear understanding of where the CL&P system stands in relation to these vital system-performance goals, it is difficult to gauge the reasonableness of costs that customers will ultimately be asked to bear in relation to their electric service, which is – in the final result – a very personal experience for each customer, notwithstanding 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. Accordingly, in combination with the testimony of the CL&P Leadership Panel, our joint testimony on the 5-Year TSP Plan is designed to give PURA and other participants in this proceeding a window into a holistic assessment of the CL&P distribution system and the Company's vantage point as to its ability to meet the demands of customers and needs of the Connecticut economy from now into the future, while providing transparency on the investment levels that are required to fulfill those obligations.

Q. What is the structure of the investment plan that the Company is presenting in this proceeding?

A. As described in detail below, the Company has structured three levels of potential investment for the CL&P distribution system over the next five years.

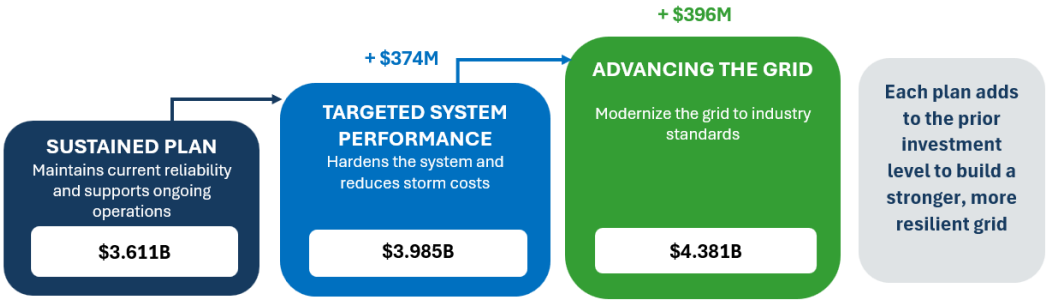
First, the Company is presenting its baseline investment plan, referred to as the "Sustained Performance Plan", which is necessary to sustain reliability performance at levels that the Company has generally maintained since the last rate case in Docket No. 17-10-46 (2018). The baseline investment plan is the minimum level of investment needed to maintain reliability performance; meet regulatory obligations; and maintain asset health and foundational system planning capacity for safety and reliable operations.

Second, the Company has developed a supplementary tier of investment directed at achieving an escalating level of asset-health replacements and enhanced reliability performance, while also commencing a system resiliency initiative. Together, the baseline investment level and this supplementary tier enable the Company to target enhanced reliability and to advance asset health and resiliency projects that would improve performance on major event days, while lowering emergent and storm costs. The Company views this 5-Year Targeted System Performance Plan to represent an integrated approach to achieving and sustaining an incremental improvement for reliability and resilience, as compared to today's operations.

Third, the Company is presenting an investment plan that would build on the 5-Year TSP Plan over the longer term, accounting for investments related to state policy initiatives and higher standards of innovation and software tools. This higher level of investment starts with the 5-Year Targeted System Plan and adds investments that support DER integration and clean-energy advancement, along with increased use of AI/ML innovations, advancing the grid toward modernization.

Figure 1 below illustrates these three investment plans.

Figure 1: 5-Year Investment Plans



Q. How is your joint testimony organized?

A. Section I of this testimony is the introduction and overview. Section II provides the Company's perspective on the state of the CL&P distribution system, accompanied by analytical support presented in Exhibits CLP-TSP-2 and CLP-TSP-3. Section III reviews the Company's planning strategies for three core areas of operational focus, which are (1) asset health and integrity; (2) system capacity; and (3) grid modernization.

Section IV provides a roadmap of the organization of the 5-Year TSP Plan, as presented in Exhibit CLP-TSP-3, and reviews the Company's strategy for investment and expenditures correlating with the 5-Year TSP Plan, in order to provide PURA with insight into the decisions that the Company is requesting in this proceeding as to the level of revenue support that should be provided through distribution rates, keeping realistic expectations and affordability clearly in focus. This section identifies and provides a brief overview of the components of the baseline investment plan for sustained operations, as well as walking through other investment levels.

Section V reviews the Company's proposals for performance metrics and analytical frameworks to gauge the Company's performance on the TSP Plan over time.

Section VI discusses the requirements set by PURA for this general rate proceeding in its final decision in Docket No. 17-12-03RE08, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Resilience and Reliability Standards, (August 31, 2022) (referred to herein as "Docket No. 17-12-03RE08" or "Reliability and Resiliency Frameworks"). Section VII is the conclusion.

Q. Would you please identify the exhibits submitted in support of this testimony?

A. Yes, this joint testimony is supported by the following exhibits and documentation:

Exhibits	Description
Exhibit CLP-TSP-1	Joint Testimony of Lavelle A. Freeman, David L. Gladey, Jennifer A. Schilling, Dr. Elli Ntakou and John DiPaola-Tromba
Exhibit CLP-TSP-2	Summary Narrative on the State of the System
Exhibit CLP-TSP-3	Presentation of the 5-Year Targeted System Performance Plan
Exhibit CLP-TSP-4	Climate Change Vulnerability Study[2]
Exhibit CLP-TSP-5	LED Dimmable Streetlight Report[3]

II. State of the CL&P Distribution System

Q. What is the Company's perspective on its obligation to maintain and care for the CL&P distribution system and to serve customers on a safe and reliable basis?

A. As the owner and operator of the electric grid, the Company's perspective is that it is the caretaker of a living and breathing electric grid that is relied upon as the cornerstone of a modern society, creating a fundamental obligation to meet the challenges of that role. Electric distribution service is classified as "essential critical infrastructure" for the very reason that it functions as the *primary enabler* for all other critical sectors, including healthcare, financial systems, communication and transportation and other public support systems. Consequently, as a matter of public health and safety, CL&P's

2 This report is submitted in compliance with Order No. 13, from Docket No. 17-12-03RE08, at 96.

3 This report is submitted in compliance with Order No. 13, from Docket No. 17-10-46.

distribution grid is necessary to keep essential facilities running such as hospitals, water-treatment facilities, communication networks and to maintain temperature control across a spectrum of electric uses for the health and safety of consumers. As a matter of economic growth and security, CL&P's distribution system is needed to support commerce throughout Connecticut as businesses rely on CL&P to provide reliable power for daily operations, manufacturing, cloud data processing, refrigeration, lighting and commercial transactions, among other functions. And most important, as a matter of daily life for Connecticut's residents, CL&P's distribution system is needed to support modern conveniences such as smartphone use, internet access, lighting, refrigeration and transportation systems, which face disruption without safe and reliable electric service.

In light of this critical mission, the Company takes its obligations to customers very seriously and works every day to meet the challenges of that role in a manner that is responsible and fully committed. The Company strives to embed that commitment to customers in its day-to-day operations, hiring practices and long-term business strategies and consistently prioritizes the interests of customers, even when it means making difficult decisions.

Q. Please describe the inherent strengths and weaknesses of the CL&P distribution system and the Company's perspective on its ability to uphold its essential service obligations?

A. CL&P's electric distribution system is a large, complex and aging infrastructure

network operating in one of the most challenging environments for overhead electric delivery in the United States. The distribution system serves approximately 1.3 million customer accounts across nearly 24,000 circuit miles, traversing a geographic area that is simultaneously one of the most densely populated and most heavily forested jurisdictions in the nation.

Although the CL&P system is a relatively outmoded system, it has continued to perform well for customers, so long as there is adequate and consistent investment made to maintain the system in its current state, which the Company has achieved. However, a growing body of data demonstrates that the condition, age and structural limitations of key assets are creating increasing risk to safe and reliable operations. Currently, equipment failures account for roughly 35–40 percent of outages under blue sky conditions. Assets that are susceptible to age-related deterioration and the cumulative effects of environmental exposure, are experiencing failure rates at an increasing rate, driving outage frequency on blue-sky days. Increasing emergent failures typically result in increasing customer outages, are costly and have the impact of taking away resources that could be dedicated to proactive replacement activities.

Consequently, as demonstrated in Exhibit CLP-TSP-2, the system is facing sizable operating challenges that are a product of outmoded designs implemented under different operating conditions, coupled with the demands of C&I development, advancing electrification trends and DER adoption, a maturing and expanding forest canopy, and intensifying storm climate. Although investments in the past have

consistently proven to be "right sized" to maintain reliability on the system, the system is at a crossroads where a step-up in investment is needed. For example, among other targeted objectives, additional strategic investment in asset-health replacements and system capacity is vital to address these emerging risks and ensure long-term system performance. These are evolving challenges that the Company must solve dynamically, systematically, cost-effectively and with full transparency to regulators, state policymakers and – most importantly – to customers who depend on and pay for this infrastructure.

Q. What are the Company's primary areas of focus in the 5-year TSP Plan, given the current operating state of the system and the need to factor in affordability considerations?

A. In today's operating environment, "affordability" can feel like an intractable and insurmountable challenge – and it may be in certain respects. However, the Company's approach to data-driven lifecycle cost-based investment planning maximizes value for customers. Setting aside the need to resolve issues of resource adequacy and the impact of the public-benefits part of the bill – both of which are major drivers of cost on the customer's bill in Connecticut – proactive investment targeted to certain aspects of the system would help to maintain rate stability across time, or even actually lower bills for customers in certain circumstances. To that end, for CL&P, the primary areas of focus must be: (1) maintaining asset health through proactive programs that anticipate declining asset health and asset retirements and make replacements on a cost-effective basis; (2) adding system capacity to support new loads associated with C&I

development and electrification end-uses that expand the volumes across which rates are collected; and (3) supporting longer-term system modernization initiatives to achieve higher levels of efficiency and effectiveness in operations, including initiatives that lower storm costs.

Q. What is the Company's perspective on a strategic plan to address asset health on an affordable basis?

A. Based on its holistic assessment of the system, the Company sees a need to ramp up programs that address asset health on a more proactive basis, given the age and condition of the system and the increasing demands placed on its aging infrastructure. At this point, there is no getting around the fact that the majority of the CL&P distribution system was constructed decades ago under significantly different operating conditions. Implementing more proactive asset-health replacement programs will provide a clear and measurable benefit in addressing this challenge. Replacing transformers and aging poles, upgrading substandard equipment and converting bare copper wire conductors to more resilient configurations will reduce the probability of failure before outages occur. This approach is critical to maintain reliability by preventing interruptions rather than reacting to outages after the fact. Proactive replacement will also enhance safety for the public and for the Company's employees by reducing the likelihood of downed wires, pole failures and equipment malfunctions. Eversource uses a structured, data-driven process to evaluate asset condition and overall asset health. Inspection results are reviewed alongside maintenance history, asset age, estimated remaining useful life, design and standards compliance, and

obsolescence factors such as replacement equipment availability. These inputs are assessed through analytical review and targeted field inspections. This approach helps ensure that asset condition evaluations are consistent, well-supported, and aligned with safety, reliability and long-term system needs. Accordingly, the Company has factored these considerations into the 5-year TSP Plan framework and stepped up the level of annual investment contemplated over the five-year planning horizon.

Q. Would you provide some examples of the types of equipment that are addressed within the Company's asset-health work plan?

A. Yes, a primary example is transformers, switchgear, breakers, batteries, and other ancillary equipment necessary to operate the electric system. For example, approximately 42 percent of the Company's bulk transformers will be over 50 years old by 2031, which is twice the ratio of older transformers on the Massachusetts and New Hampshire systems. Although asset age is not a direct indicator of asset health, older transformers have a greater likelihood of failure, which exponentially increases after 70 years old, primarily due to paper insulation degradation. During the replacement of a transformer, Eversource will typically replace the other aging equipment associated with the unit. In addition, new transformer installations typically include monitoring equipment, modern protective relays, and oil containment systems. These coordinated replacements maximize work efficiencies and ensure that the new transformer has up-to-date monitoring and protections to maximize its capacity and expected life span.

Items such as switchgear, Load Tap Changer ("LTC") controls and electro-mechanical relays on the Company's system are increasingly becoming obsolete and require accelerated replacement to avoid failures. Batteries, station service transformers and monitoring systems also need renewal to maintain substation availability. Oil-filled equipment and other environmental risk assets require replacement to reduce spill risk and avoid environmental exposure. Eversource has established programs to address the asset classes described above. These programs establish plans to proactively replace aging and deteriorated distribution infrastructure. The programs prioritize safety, reliability and cost-effectiveness and projects are integrated into the long-term planning, capital investment, and asset management processes. These programs support safety, system reliability, regulatory compliance, risk mitigation, and long-term infrastructure sustainability by proactively replacing distribution assets that have reached the end of their useful life of service or present an increased risk of failure.

Q. What are other examples of asset-health considerations on the current CL&P system?

A. Other examples include continued utilization of bare-wire conductor on the Company's system. The CL&P system currently encompasses approximately 24,000 circuit miles, of which 71 percent or approximately 17,000 circuit miles comprise the overhead distribution system. Today, after years of investment to upgrade and replace aging overhead assets on a system-maintenance basis, the overhead system continues to utilize approximately 7,500 miles of bare-wire conductors, constituting 47 percent of

the Company's overhead circuits. Bare-copper conductor has no protective cover on the outside, so when a tree limb makes contact with system infrastructure in areas where bare-copper conductors are in use, there is a high risk of a fault (or short-circuit) between energized conductors or between energized conductors and the electrical ground, leading to immediate customer interruptions under blue sky and storm conditions. Bare-copper conductor at end of life (~50 years) exhibits annealing which reduces the tensile strength of the wire, leading to fatigue failure at the connectors, which can also be a safety concern whenever personnel are working on addressing this type of asset condition. Bare-copper conductors are typically replaced by tree wire that is designed to prevent tree contact with energized conductors, thereby protecting against an immediate interruption of power to customers on the circuit. Proactive replacement of overhead bare-copper conductors coupled with an aggressive vegetation-management program will make a significant difference to customers in relation to outages that are experienced even under blue sky conditions. Further, approximately 76 percent of the wood-pole fleet are legacy poles that do not meet current strength standards. Replacement of the poles and conductors strengthens the structure of the circuits and contributes to lowering the likelihood of customer interruptions caused by pole or conductor failures.

Similarly, approximately 14 percent of the Company's overhead distribution system is comprised of legacy 5kV infrastructure that needs to be converted to higher standard voltages for better operability, improved voltage regulation and increased capacity.

This infrastructure is problematic because 5kV is an older, lower distribution voltage that is highly inefficient for modern power demands limits. Elimination of this infrastructure and replacement with 13.8kV wire or higher will result in a more reliable and cost-effective experience for customers.

Q. What is the Company's perspective on a strategic plan to address system capacity on an affordable basis?

A. Substation capacity is a significant challenge for the CL&P distribution system. Electric substations act as the critical gateways and potential "bottlenecks" of the power grid, dictating how much electricity can safely flow from transmission lines to local neighborhoods by transforming voltage levels and managing power flow within equipment thermal limits. If a substation reaches its maximum capacity, no additional power can be routed to that area without the risking catastrophic equipment failure, customer and worker safety, and prolonged loss of power supply to customers. Substation capacity is the maximum electrical load a substation can handle while remaining within thermal equipment ratings and operating criteria. Substation capacity is frequently expressed in megavolt-amperes ("MVA") and reflects the combined capability of transformers, busbars, switchgear, protection systems, and the connected circuits within the substation facility. Thus, substation capacity is determined by the combined thermal and electrical limits of its transformers, switchgear and circuit breakers. If local electricity demand (like from new EV chargers or other electrical end uses) exceeds the limits of the substation feeding the area, the substation becomes a bottleneck and grid operators cannot safely route more power to the area.

In addition, electric substations are designed with contingency criteria in mind. Although a substation may have a high "installed capacity," its "firm capacity" is often much lower. Firm capacity represents the maximum load the substation can handle even if one of its transformers, buses, breakers or incoming lines fails, ensuring the grid remains reliable during outages, as such outages of major equipment could take weeks to months to rectify leaving customers at risk for prolonged interruptions during such time. Lastly, the size and condition of the Company's electric substations determine capacity to accommodate the *inflow* (or reverse flow) of power from distributed generation. "Hosting capacity" refers to how much distributed energy, from resources like solar panels or wind turbines, can be integrated into the distribution system at specific locations without disrupting safe, reliable service for other customers. Because substations are common connection bottlenecks, available substation capacity is a major factor in deciding where new DER projects can connect and what reinforcements may be required to accommodate them.

Q. Why is substation capacity an emerging challenge for the CL&P system?

A. As development across the state has occurred over the last decade, several ramifications have occurred for the CL&P distribution system. That is, the Company's legacy bulk substations are located where the customer loads are. Historically, as substation overloads start occurring, the Company has been able to "de-load," by re-distributing load using nearby distribution assets rather than upgrading the substation to accommodate the load. Now, with persistent development within the State of

Connecticut, the "nearby" distribution infrastructure is also becoming overloaded, creating an area need on a scale that requires a more significant infrastructure development project to eliminate violations of substation asset thermal limits, and sustain economic growth.

At the same time, high DER penetration is predominantly located in areas which are almost the total opposite of customer load penetration. DER facilities, especially large front-of-the-meter projects, tend to locate in the eastern and northwestern regions of Connecticut where land is relatively inexpensive and abundantly available but there is very little customer load and consequently less electrical infrastructure. Thus, while the Company is planning for customer load and building or upgrading substations to accommodate that load growth, DER penetration is causing performance issues on the system during low load periods when DER is exporting a significant amount of power (a good outcome), causing overloading of smaller substation infrastructure and transformers (a challenging outcome). As a result, to support the interconnection of DER applications that are helpful to the system in relation to renewable energy supply, the Company needs to be planning for substation upgrades in those areas, although customer load growth has not yet reached those locations.

Q. Why is it important to support system capacity?

A. With respect to the issue of system capacity, the Company is referring to changes that are occurring in the types of businesses and facilities that are seeking to locate in

Connecticut and the locations that are attractive for that development, which is tending to be the more undeveloped parts of the State due to the affordability of property.

In fact, from a Connecticut distribution-system perspective, an underlying consideration that rarely receives attention is that commercial and industrial ("C&I") load is critical to lowering the cost of electric service for customers. C&I customer load allows costs to be spread across larger volumes of "output" and, where costs are increasing, growth in electric sales is critical to help maintain affordable bills, or even to lower costs for customers. Yet, in Connecticut C&I customer load has decreased precipitously over the past decade and new C&I load faces serious obstacles in coming to Connecticut.

For example, in Massachusetts, NSTAR Electric serves approximately 1.3 million customer accounts, with approximately 64 percent of its load associated with C&I customers. In Connecticut, CL&P similarly serves approximately 1.3 million customer accounts, with approximately 51 percent of its load associated with C&I customers. Even if C&I customers are considering entry to the State, the Company is increasingly finding itself in a position where the customer is attempting to locate in a relatively less developed area of the state (and less expensive); however, there is not sufficient electric infrastructure to support that customer without significant system upgrades that cannot always be completed on the potential customer's timeline. The distribution system does not have the innate capacity to serve new loads in those more rural (and less expensive) areas because, historically, there has not been population growth in those

areas to draw electric infrastructure to that location. Co-siting economic development zones with DER development areas would be a productive foray for that reason.

For example, the Company was approached by a Canadian company that was trying to build solar panels in eastern Connecticut, and the Company could not support their new load in that location *within their timeframe* because there was *no substation* close to that area, let alone available substation capacity from the nearest existing station. Similarly, large commercial customers have approached CL&P to explain that Connecticut has become the strategic core area to move product within New England, and new warehouses and other facilities are needed in Connecticut to support those operations. The Company's challenge is that these types of loads require significant amounts of substation capacity, which does not exist in the more rural eastern part of the State. Even if substation facilities are within proximity of development, there are at least eight substations on the CL&P distribution system where the Company is unable to connect another single megawatt of DER because it would overload the Company's transformers. Progress is therefore stopped in these areas.

As a result, the Company is reaching a point of inflection where it is very limited on what it can do to meet the needs of these types of customers or the needs of distributed energy resources that want to connect to the system in these areas -- because it requires capacity, which in turn requires investment in the electric system beyond any level that the Company has invested in the past. Economic development or electrification end-uses that bring electric sales volumes to the State will have a positive impact on

CL&P's residential customer bills because it will spread the fixed costs of the system across a broader base, volumetrically. The Company's proposal for allocating the cost of major substation upgrades for DER between DER and load customers (Exhibit CLP-TSP-3, Slides 141-149) could create capacity in these areas to support economic development at a lower cost to customers.

Q. What is the Company's perspective on the tools that need to be used to design and plan for a modern electric distribution grid on an affordable basis?

A. The Company's perspective is that technology and data-driven analytics are vital tools in achieving the balance of curating system needs while maintaining affordability for customers. In that regard, over the past several years, the Company has strived to implement innovative technologies and advanced analytics to lower costs and optimize outcomes for customers in four distinct areas. The first area is increasing grid visibility and control through grid sensors, remotely controllable overhead and underground switching, and smart voltage control devices enable data-driven analytics and intelligent real time decisions. The second area is Artificial Intelligence and Machine Learning (AI/ML) analytics that can provide data-driven insights into resiliency and reliability planning, storm response optimization, capital investment decisions, load and generation forecasting, and asset management tools. The third modernization area is the use of mobile tools that increase operational efficiency to dispatch work, perform asset surveys, document as-builts, and manage damage assessments and crew workforces following storm events. The fourth area is operational optimization,

including implementation of the "control room of the future" by integrating asset data and real-time telemetry into power-flow driven tools for safe, reliable grid management and restoration.

III. Investment Planning Approach

Q. How does CL&P approach system planning at the ground level?

A. Over the past several years, the Company has developed a data-driven approach to capital allocation. As an example, to cost effectively improve reliability from a system SAIDI and SAIFI standpoint. To that end, Eversource has developed a state-of-the-art, benefit-cost analysis model that looks at historic outages at a microscopic zonal level, rather than at the circuit level. The model incorporates the Company's historical data regarding the upgrades made in the past 20 years and analyzes the benefits, specifically, SAIDI and SAIFI benefits for every dollar spent. The Company has also better attenuated that model to be able to have better prediction around a determination to increase performance by a designated amount, for example, if the decision is to improve SAIDI by 5 percent or SAIFI by 5 percent, or whether it is given different objective functions. The model goes into different zones and comes up with the most cost-effective upgrade for a given zone, which could be anywhere from a simple tree trimming to a full rebuild and everything in between. In addition, for system planning projects, the Company uses detailed state-of-the-art distribution planning models that represent not just the various distribution stations, but also interconnectivity between adjacent substations and all the distribution feeders associated with it. Eversource

maximizes the utilization of load transfers among stations and exhausts all options before arriving at the decision to upgrade a given transformer at a given substation and ultimately significantly improving capacity of the grid.

Similar data analytics are used for the Company's replacement and safety-driven programs. The Company looks at how many miles of overhead conductors exist on the system that are brittle, like bare copper wire, or how many miles of paper insulated lead cable (PILC) should be replaced given implications to safety and reliability. The Company looks to all of these data points and assesses the right amount of investment that is necessary to manage risks in the most cost-effective manner, balancing risk reduction with affordability in every aspect of the engineering and planning function. For example, from a substation transformer asset condition standpoint, over 42 percent of the Company's substation bulk transformers are over 50 years old. That percentage is about two times what that percentage is in any other jurisdiction within Eversource, highlighting the age of the Company's substation fleet and not just substation transformers, but also substation equipment.

The Company uses a data-driven approach, including but not limited to outside experts such as Lawrence Berkeley National Lab and EPRI, and the Company built its own Monte Carlo simulations to be able to assess what is the right size and what is the right amount of transformer replacements that should be developed in a given year so that the tail of the asset base gets to a place where the Company is no longer trying to play catch up with safety and emergent failures of substation assets. The Company also has

industry benchmarking that highlights the age at which transformers start to rapidly degrade after 70 years in service.

From the capacity perspective, one of the things to note is that substation capacity is the foundation and the underpinning for how the Company provides reliability all the way down to the distribution circuits. Adequate substation capacity reduces the risk to customers due to prolonged outages, because if a substation transformer fails, it could take weeks to months to replace that transformer and customers are at risk of prolonged outages if the Company does not build sufficient operational flexibility within the system. This means that, when the transformer fails, the Company needs to be able to move load either to the next substation transformer or transfer load to adjacent substations. Therefore, the Company's analysis looks at the substation fleet and understands the thermal capacity rating of each transformer and does analysis to figure out how the transformers can support load based on ambient conditions and based on the load profiles that are observed and forecast 10 years ahead the load on the system at a 90/10 probability level. The Company imposes this load on every bulk distribution substation based on its local characteristics, and then does analysis using state-of-the-art tools to understand whether there are violations and when these violations occur on each substation, and then determines how these substations should be upgraded or whether other solutions that are less costly and can defer expensive upgrades should be enacted, such as non-wire alternatives and distribution transfers.

The Company takes the approach of looking at the lowest cost solutions that technically

meet the load demand, and then progressively looks at more expensive solutions that provide incremental benefits in alignment with the long-term energy needs of the area. The Company does a similar analysis with DER, looking at the impacts of DER on the distribution feeder and on the substations, i.e., when the output is high and load is low, and does analysis using some of the very same tools to understand the performance characteristics and the violations, how each and every piece of equipment on the system would be impacted by the load, would be impacted by voltage profile, power quality, operation of equipment that needs to switch, and determines what mitigation measures should be needed to maintain the performance of the system and to ensure that load customers are not adversely affected. Then, the Company develops solutions to resolve those measures and monitor those solutions to ensure that they are viable over the lifetime of the system.

One thing to note is that, when evaluating bulk substations, the Company is looking at the bulk substations that are supplying *an area*. These solutions should be developed so that the solutions actually resolve the constraint in the load pocket. When considering the ability of a battery storage solution to meet infrastructure needs, the Company also looks at whether those non-wires alternatives are able to meet the needs of the wider area solutions and to provide the same operational flexibility needed to maintain reliability all the way down to the edge of the system.

Q. How did the Company use these analytical strategies and tools to develop the system resiliency plan that the Company is recommending as part of the 5-Year TSP Plan?

A. The system resiliency component of the 5-Year TSP Plan is an example of a data-driven approach based on historical performance and predictive analytics. To generate this approach, the Company looked at past years of storm performance, including the four most recent major storms, as well as minor storms, and has evaluated where and to what extent these storms impacted the system; the cause of interruptions during every storm; the number of customers impacted; and how long those customers were impacted. The Company evaluates impacts down to the zonal level and determines what mitigation measures would be effective to reduce the number of customers impacted and the length of those outages. These measures range from undergrounding conductors to reconductoring with spacer cable; converting wood poles to steel poles; even installing aerial cable; and, of course, vegetation management.

The Company also takes a forward-looking approach by understanding the type of conductor or equipment that fails, the characteristics of that equipment, the design limitations and the tree risk of each zone. This signature is then used to identify other pieces of equipment in other places on the system that have the same characteristics. So, even if that conductor did not fail during a past storm, it has the same characteristics, the same design, the same tree risk as the conductors that fail. This plays into the predictive analytics where the Company now looks at whether those conductors or those pieces of equipment with the same characteristics as the ones that

fail historically, what would be the impact on customers. In this way, the Company is able to mitigate historical occurrences, but we also use history to predict what would happen to other pieces of equipment that are at risk and develop the same type of solutions to mitigate those predicted risks for customers, allowing us to hedge against what could happen in the future. The Company also does analysis to figure out what is the result of this on customer minutes of interruption ("CMI") and the number of customers interrupted ("CI"), which translates to SAIDI and SAIFI, and then takes it another step further to look at what is the benefit to customers.

Using the ICE calculator from Lawrence Berkeley Labs, the Company can translate resiliency performance or translate CMI and CI into the value of loss load, which is an assessment of the impact of poor reliability on customers and how much it costs customers when storms happen, which enables an evaluation of the benefit of these resiliency measures in terms of cost savings to customers. The Company has also developed storm analytic tools that allow us to look at how it can optimize operational performance, meaning dispatching crews for damage assessment, to reduce the truck roll mileage, even to optimize the number of crews that could be mobilized to efficiently do damage assessment, which enables the Company to reduce storm costs.

IV. Roadmap of the 5-Year TSP Plan

Q. Would you please describe the overall organization of Exhibit CLP-TSP-3?

A. Yes. As an initial matter, the Company approaches its planning and operation of the

system in relation to three operating divisions, which are the CT Western Division, the CT Central Division and the CT Eastern Division. Accordingly, the Company's presentation in Exhibit CLP-TSP-3 starts with a brief review of the overarching system objectives (Slides 3-12). Exhibit CLP-TSP-3 then provides a comprehensive analysis of the current state of the system covering several bases, including: (1) a regional overview; (2) load growth considerations; (3) capacity considerations; (4) DER integration impacts; (5) reliability performance; (6) and asset health. In this section, the Company provides general system-performance statistics by region, including trends in capacity needs for customer load and DER facilities; and (2) trends in reliability and resiliency performance (Slides 13-38). The overview of the state of the system discusses trends in asset health and associated operating risks and opportunities. This section also analyzes DER installations and the growing complexity of work surrounding the interconnection of DER in the future. Other considerations covered in this section are the nature of information systems technology used for system efficiency and optimization and compliance with regulatory and policy requirements.

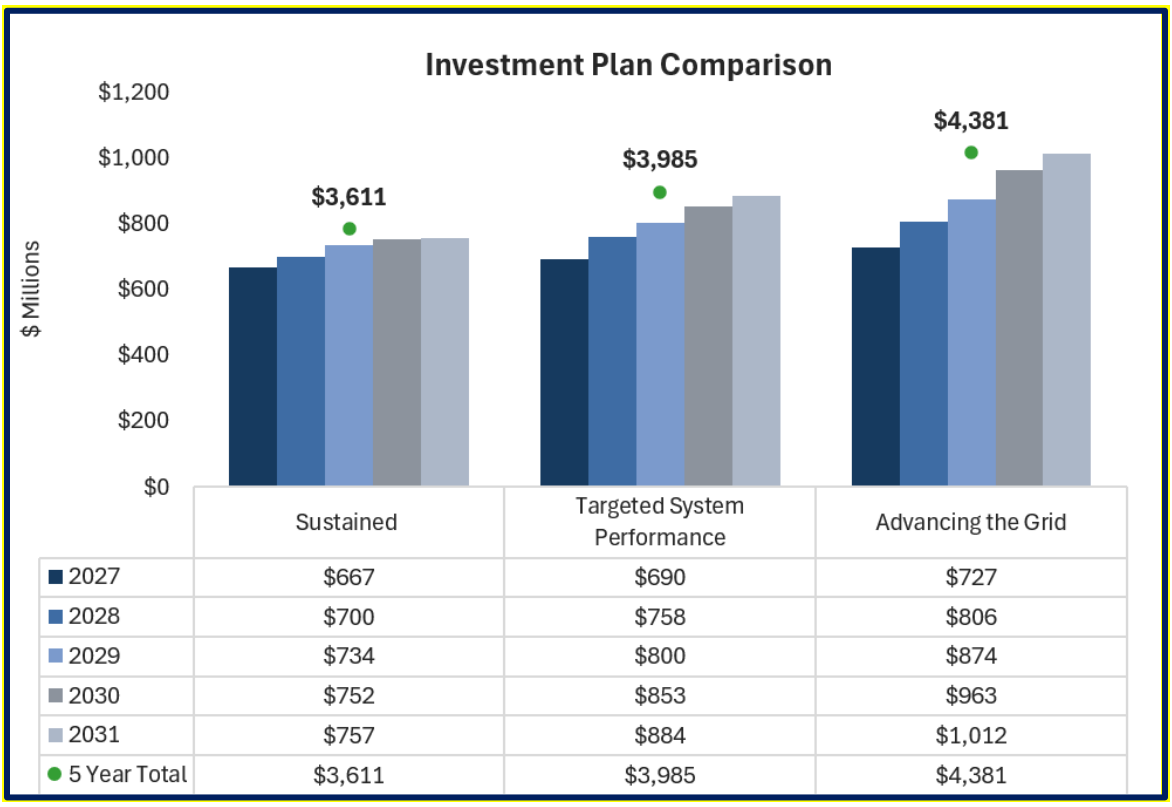
Q. Does Exhibit CLP-TSP-3 provide detailed information on the capital investment encompassed in the 5-Year TSP Plan?

A. Yes, it does. The Company's capital investment plan covers a number of program areas that are focused on supporting the performance of the system while fulfilling customer demand. The Company assesses the data and performance of the assets on the system and works to prioritize the data to meet the highest cost beneficial performance result

for the system. The end result of this work is to determine the investments included in the 5-year TSP Plan budget, which is the investment level that is needed to make sure that the Company is able to achieve safe and reliable operation of the system.

More specifically, at Slides 39-44, the Company has provided a breakdown of the budget components of the 5-Year TSP Plan. The 5-Year TSP Plan is comprised of two subcomponents: (1) baseline investments that are necessary to maintain existing reliability levels ("Sustained Performance"); and (2) a supplemental tier of investment targeted at achieving reliability improvements and implementation of a dedicated system resiliency plan ("Enhanced Reliability and Resiliency"). A third tier, "Advancing the Grid," would allow for investment in advanced grid modernization technologies; however, the Company's assessment is that these types of upgrades are a longer-term proposition for Connecticut. The table below compares the details of the three investment plans.

Figure 2: Investment Plan Comparison for Program Years 2027-2031



	Sustained	Targeted System Performance	Advancing the Grid
2027	$667	$690	$727
2028	$700	$758	$806
2029	$734	$800	$874
2030	$752	$853	$963
2031	$757	$884	$1,012
5 Year Total	$3,611	$3,985	$4,381

Figure 2, above, shows that the Company's 5-Year TSP Plan contemplates investment of approximately $667.3M in 2027 for the Sustained performance level, with an additional $22.7 million identified for the supplemental tier, totaling approximately $690 million for the year. In 2027, implementing the third tier, "Advancing the Grid," would require an additional annual capital expenditure to approximately $726.5M. It is also important to note that the 5-Year TSP Plan shown above is reflective of the engineering capital plan, exclusive of capital expenditures needed for Information Technology, Facilities and certain Basic Business items. These additional items and the correlation to the engineering portion of the overall capital plan are shown in Slide

41 of Exhibit CLP-TSP-3 (Financial and Engineering Categories).

Slides 45-81 of Exhibit CLP-TSP-3 provide detailed information on each category of investment within the 5-Year TSP Plan, pertaining to distribution integrity and substation capacity.

Q. What is driving the need for a targeted system resiliency plan?

A. The distribution system is built with redundancy, principally circuit ties and back-up sources, sized to 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 conductor creates an immediate fault and a sustained outage for every customer downstream. This construction was cost-justified under the weather patterns and customer expectations that prevailed when it was installed; 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 combining 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 outage impact 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 35 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.

Taken together, these factors establish both the need and the cost of inaction. The estimated annual Value of Lost Load attributable to customer outages is approximately $689 million, and a single Isaias-equivalent storm represents an estimated $10.6 billion in economic harm to Connecticut customers and businesses. Accepting the current level of vulnerability is therefore not a cost-free choice. A targeted resiliency plan focuses investment where it will do the most good, 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. 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 operating and maintenance ("O&M") expense and to conduct its capital work plan with rigorous authorization and oversight processes, cost controls, and efficiency. The primary strategy that the Company seeks to expand across the range of its asset health programs in the 5-year TSP Plan is a more proactive 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 in changing climate conditions and evolving grid demands, including advanced system automation, increased electrification and higher penetration of DER. 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 fact. 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 capital funding up-front, these types of 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 among 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 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.

Managing asset health using an approach that expands 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 in these operating circumstances.

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 has a negative impact on customer convenience and welfare, but it 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 assess, formulate and validate an investment plan to support the identified system needs, while balancing affordability considerations. As delineated in Exhibit CLP-TSP-3, the Company is presenting budget options for PURA's review and consideration in this regard so that PURA can develop its own perspectives on the appropriate balance between the needs of the system and the reasonableness of cost levels for customers.

There is a direct tie between the rates that PURA sets and the tools that the Company has to implement to provide distinct service levels to customers. Therefore, the Company has worked to provide PURA with optionality to synchronize PURA's expectations for grid performance with costs to customers.

Q. Is the Company's 5-year TSP plan for increasing investment on the distribution system a critical need that is in the interest of customers?

A. Yes. Without increasing investment, CL&P's distribution system will continue to fall behind, creating a material impact on the opportunities for meeting the demands of a modern society, as well as the affordability of electric service for Connecticut customers. The 5-year system plan addresses this reality and plans for investment in storm hardening, automation, data-driven targeting of the highest-risk infrastructure, underground cable renewal and pole replacement. The 5-year TSP Plan is a coherent, evidence-based strategy for improving system performance over time. No single investment eliminates the risk. Instead, each targeted investment measurably reduces risk for the customers in the operating zones that need it most and reduces O&M expense for the future.

Q. Please review the categories of capital programs that comprise the Company's baseline investment plan and that the Company conducts to sustain the integrity of the distribution system and maintain reliability.

A. As noted above, the Company has developed three levels of potential investment on the system, which are: (1) baseline investment to sustain operation of the system and maintain existing reliability; (2) enhanced reliability and resiliency (which together

with baseline investment comprises the Company's 5-Year TSP Plan proposal); and (3) investments for the future to advance and modernize the electric grid.

Sustained Performance

The primary capital programs that the Company conducts to meet system needs and objectives are as follows:

A. NEW CUSTOMER LOAD

New customer investments reflect growth in our territory including new residential and commercial developments, installation of services, expansion projects for existing customers, interconnections for new systems and distributed generation projects, all net of customer contributions. There has been increased growth in the number and amount of expenditure for larger, more complex customer projects. The smaller, less complex projects have maintained a similar level of expenditure in the past years since the last rate case. The need to upgrade Eversource systems for capacity has increased due to these large customer demands. Baseline funding for the investment category is ~$80M per year for the next 5 years.

B. PEAK LOAD/CAPACITY

Peak Load/Capacity Projects address existing or forecasted overloads on substations and lines due to more power being required by customer loads than the system equipment can support without violating thermal limits, which could result in failure of the equipment and customer interruptions. Insufficient capacity on the system also

limits or eliminates the Company's ability to provide operational flexibility to enable outages to be isolated and restored through alternate sources. At the bulk distribution substation level, the system is designed to sustain failure of any single station component with no loss of customer service. This requires that, under normal operating conditions, substation equipment does not exceed 75 percent of the normal rating, and under contingency (abnormal conditions), does not exceed 100 percent of emergency rating.

For distribution lines, the design criteria states that under normal conditions underground cables are not to exceed 80 percent and overhead conductors are not to exceed 90 percent of the normal rating. Under contingency, both underground cables and overhead conductors cannot exceed 100 percent of normal ratings. Measures to address capacity overloads in a cost-efficient manner include: 1) balancing load across the system by transferring customers to other substations, buses, transformers or circuits; 2) increasing the rating of existing equipment (by cooling, for example,) or replacing limiting equipment with higher rated equipment; 3) adding or installing new facilities to accommodate the increased demand; and 4) using non-wires alternatives, such as DER and demand response, to reduce loading during peak periods. Average baseline funding for the investment category for the next 5 years is ~$50M per year for substations and ~$19M per year for lines.

C. ISO-NE COMPLIANCE

ISO New England (ISO-NE) notified Eversource that its 2025 reactive power interchange performance did not meet the requirements of Operating Procedure No. 17 (OP-17 Rev. 9) and the Transmission Planning Technical Guide (TPTG). The review evaluated hourly reactive power interchange performance for the period January 1, 2025 through December 31, 2025 and identified specific Eversource service areas that exceeded allowable reactive power interchange limits.

Eversource must develop and submit a mitigation plan that identifies root causes, corrective actions, implementation milestones, anticipated return-to-compliance date, and supporting activities including budgeting, engineering, procurement, cost review, and construction. Once studies are completed, field changes will be required to address areas where capacitor banks need to be replaced, added or upgraded.

Poor load power factor can create transmission system reliability and voltage control challenges, including increased switching of capacitors and reactors, commitment of generation for voltage support, DER curtailments, transmission equipment wear, and reduced system flexibility.

ISO-NE requires Eversource to make any system changes required by January 1, 2031. This capital investment is required to meet the ISO-NE timeline.

D. OVERHEAD AGING INFRASTRUCTURE

The Overhead Infrastructure Replacement supports the replacement of degraded bare copper conductor, improving public and employee safety, reliability, capacity and resiliency. Much 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. The number of failure events associated with bare copper conductors have increased by 150 percent in 2025 versus 2021. There are currently 3,774 miles of bare copper in-service in Connecticut. Baseline funding of ~ $16M per year would result in a 189-year replacement program or 144 years with ~$5M of incremental funding per year.

E. DISTRIBUTION RIGHT-OF-WAY LINES

This project category is aimed at replacing aging infrastructure in rights-of-way (ROW). These wooden poles and conductor located in ROW show visible signs of degradation with poles and crossarms also showing signs of wildlife damage. The majority of these poles are past their service life, with the average age being over 50 years. Without addressing these asset conditions, reliability will be at continued risk and susceptible to failures causing extended outages to customers. Projects are prioritized by number and severity of degraded poles, public safety, and customers at risk. Baseline funding of ~ $17M per year in the next 5 years would result in a 31-year replacement program or 25 years with ~$5M of incremental funding per year.

F. UNDERGROUND CABLE & EQUIPMENT REPLACEMENT

UG Cable & Equipment Replacement projects support the replacement of Paper Insulated Lead Covered (PILC) cables used on distribution circuits. These vintage PILC cables were mainly used on circuit getaways and in network areas up until 1984 with a 40-to-50-year service life expectancy. Most in-service PILC cables have exceeded their useful life resulting in 3 failures per 100 km or 1 failure per 20 miles of cables in operation over 45 years (CIRED – Madrid, 3-6 June 2019). Failures of PILC cables may result in customer interruptions and place the distribution system in an abnormal configuration for an extended duration of time. Underground network systems, such as those located in Hartford, are typically supplied by PILC feeders. A second failure, while already in an abnormal configuration, could lead to the de-energization of an entire network system impacting large groups of customers. Circuits with PILC cable are prioritized for replacement based on load, number of events, customers at risk and customers impacted. Benefits of replacing PILC cable include worker and public safety, environmental, reliability, capacity and customer satisfaction. There are over 200 feeders with an estimated 270 miles of PILC cable remaining in Connecticut. Baseline funding of ~ $11M per year would result in a 25 year replacement program or 17 years with ~$5.5M of incremental funding per year.

G. UNDERGROUND NETWORK AUTOMATION

Underground Network Automation projects support the replacement of aging distribution switchgear, provide quicker restoration, telemetry, and improved safety.

The replacement of switchgear that has reached end-of-life proactively prior to failure would reduce both customer outages and prevent abnormal system configurations. Switchgear replacement will enable the electrical system to be switched remotely and allow for the operators to see real time load data, which will improve the outage restoration times by not having to dispatch a crew to manually operate the gear. The newly installed switchgear is dead-front constructed (use of elbows vs bolted on connections) and provides the crews safer ways to switch customers, reducing potential injuries while improving restoration times. The replacement program is prioritized based on customers at risk and equipment condition. Baseline funding of ~$3.5M per year would result in a 41-year replacement program or 18 years with ~$4.6M of incremental funding per year.

H. DIRECT BURIED CABLE REPLACEMENTS

The Direct Buried ("DB") Cable program funds the replacement of direct buried distribution cables in underground residential and commercial developments that are reaching the end of their useful lives. It has been determined on an industry-wide basis that much of the original Cross-Linked Polyethylene ("XLP") and High Melting Point ("HMP")-insulated primary cable installed in the DB system has not achieved its engineered life expectancy. The Eversource distribution system encompasses a substantial component of DB cable which was installed in the 1970s and 1980s. At that time, the installation of the cable did not include any conduit. The current standard places all below-grade cable in conduit and/or duct system to prevent degradation. To

provide perspective, baseline funding of $28.4M yields a 200-year completion timeline in all towns in CT.

I. SUBSTATION ELIMINATION

This program provides funding for line work necessary to eliminate small, aging distribution substations with an average age of 60+ years old that, if not eliminated, will require significant upgrades and equipment replacement to remain in service. Many of these substations are "Islanded" i.e. a substation where all or most of the load cannot be picked up by alternate sources in the event of an equipment failure within the substation. The method utilized to eliminate these islanded substations is to convert the feeders to a higher distribution system voltage which will provide a means to restore customers via an alternate source for both non-storm and storm events. Additionally, these improvements will increase capacity, resiliency and reliability for Connecticut customers. There are a remainder of 14 islanded substations that impact over 20,000 customers in Connecticut. The average cost to convert these substations is $1.9M per MVA. Baseline funding of ~$6M per year would result in a 19-year replacement program.

J. SUBSTATION BULK AND DISTRIBUTION TRANSFORMERS

Substation transformers typically have a design life of 40 years. Eversource's asset health philosophy for transformers is to operate transformers to their maximum useful life, but plan to maintain a transformer fleet that does not exceed 70 years of age and

an average age of approximately 35 years. The objective is to find the balance between affordability and preventing an aged transformer fleet that approaches the "knee of the curve" which results in failure rates that increase significantly. The current average age of substation transformers is 43 years old and 178 or 56 percent are currently over 40 years old. With a large portion of the transformer fleet being between 50 and 80 years old. As these transformers continue to approach and exceed 70 years, the rate of failure risk increases rapidly. Based on historical investments of replacing an average of three transformers per year, the goal to have an average age of 35 for transformers in CT is unachievable, with the majority of the population continuing to age, approaching or exceeding the critical 70-year mark associated with rapid aging, caused primarily by paper insulation degradation. The average cost of a bulk transformer replacement project is ~$8M per unit. The Targeted System Plan includes an average of 8 bulk and distribution transformers with an investment of ~$78M per year. Increasing the replacement rate to the proposed 8 transformers annually, is required to reduce the average fleet age to 35 and under 70 within 10 years, positioning the system below the end-of-life threshold. Achieving the 35-year target shifts the system from reactive failure response to proactive asset risk management, maintaining reliability, reducing lengthy and impactful emergency replacements, and stabilizing long-term investments.

K. SUBSTATION SWITCHGEAR AND CIRCUIT BREAKERS

Circuit breakers can be installed in different ways depending on the design of the

substation. In some cases, especially in outdoor air-insulated substations, the circuit breaker is a separate piece of equipment located out in the substation yard and connected to the rest of the system by conductors and other switchyard equipment. In other cases, especially in gas-insulated or metal-enclosed switchgear, the circuit breaker is housed within an enclosed switchgear cubicle along with other components such as disconnect switches and measurement devices. There are 1,702 distribution station circuit breakers currently in service across the Company's service area. The medium voltage breaker fleet includes 351 air circuit breakers, 55 oil circuit breakers (OCBs), 23 sulfur hexafluoride (SF6) circuit breakers, and 1,273 vacuum circuit breakers. These assets support critical distribution substations and play a vital role in maintaining system reliability, ensuring safe fault interruption, and providing operational flexibility to support planned maintenance activities. The Targeted System Plan includes an average investment of $25M per year, which depending on the size of the switchgear or substation can include one switchgear and several breakers per year.

L. MAINTENANCE PROGRAMS

A. Pole Integrity

The pole integrity program accounts for the cost required to replace defective wooden poles identified during the annual pole inspection process across Connecticut. These poles must be replaced as they can no longer remain in service due to loss of structural strength, decay, insect infestation and physical damage resulting in a risk to public safety and system reliability. In 2025, Eversource updated its construction pole

standards and harmonized its inspection process across all service territories to better align with industry standards. This change shortened the pole inspection cycle from 15 years to a 10-year inspection cycle and incorporates the use of the IML tool (Resistograph). Approximately 42,000 poles are inspected annually to comply with the new 10-year cycle. The expected life expectancy of a utility pole is 40-45 years with CT poles averaging 47 years old. Baseline funding for pole integrity is ~ $16.5M per year.

B. Underground Structure Issues

Underground Structure projects support the replacement of aging underground infrastructure. These structures include vaults, manholes, service boxes, conduit ducts and addition of manhole energy release covers. Underground Structures are evaluated and prioritized based on inspections, condition of structures, and locations. The installation of these energy release covers improve safety for the public in the event of a splice or cable failure in a manhole. There are ~8,000 manhole covers in need of replacement in Connecticut. Baseline funding of ~$10M per year will replace all manhole covers with the energy release type covers in a period of 10 years.

Q. How does vegetation-management work factor into the equation, particularly in light of a need to maintain affordability?

A. Connecticut ranks at the top, nationally, in terms of vegetation growth and Connecticut's high ratio of tree canopy (75-78 percent), combined with an aging over-stocked forest (61 years+ 85 percent of the forest), creates persistent exposure to

vegetation-related damage.[4] Over the past several years, approximately 75 percent of total customer outage minutes have occurred during stormy weather events, with the CL&P system now typically experiencing 30-35 minor storm days, annually. Repeated stormy weather exposure accelerates wear and tear on system components, weakening poles, conductors and equipment over time. Without more proactive replacement, this cumulative damage leads to increased failure rates, longer restoration times and greater customer impact, at a higher cost than proactive, planned replacement, making it an imperative that the Company conduct a vigorous vegetation-management program in concert with a proactive program to replace conductors and poles to withstand the impact of vegetation damage to the system.

At the same time, although tree trimming is an important part of managing the impact to the system today, it is not the total solution in addressing the impact to the distribution system and minimizing economic impact to the state and customers and operating cost over the long run. Infrastructure originally designed decades ago under legacy standards is not at the level to sustain impact from environmental conditions without strengthening or hardening the system consistent with best utility practices.

4 State's Council on Environmental Quality 2020 report, in the Forest Section (https://portal.ct.gov/ceq/ar-20-gold/2020-ceq-annual-report-ebook/land-preserved_land/forests).

M. ENHANCED RELIABILITY AND RESILIENCY

A. Reliability SAIDI/SAIFI

The Benefit Cost Analysis (BCA) tool is utilized to determine the most cost-effective reliability improvement work to perform based on historical event data to meet a desired reliability outcome. The tool compares various work types at a device level which includes reconductoring, backbone automation, and lateral automation. Baseline funding for this program is $32M.

B. Smart Switch

The smart switch investment includes additional smart switch devices to sectionalize large zones with over 500 customers to zones that are less than 500 customers to reduce the number of customers impacted by an event. The additional smart devices will provide telemetry and the ability to isolate zones that would have a high impact on reliability in the event of a future outage. Under baseline funding, the smart switch program is not funded, sectionalizing all zones to below 500 customers would take 9 years under the Reliability SAIDI / SAIFI program alone. Adding the incremental funding of $5M under the Smart Switch program would reduce the time to sectionalize all zones to 6.5 years.

C. Distributed Energy Resource Management System (DERMS)

The future of the grid is more DER aware and ultimately leveraging all types of batteries, solar inverters, demand response. The Company is planning to take all of these resources and to turn them into grid assets, which is both cost effective as well as

helps us to optimize how we invest in our system. DERMS will enable the Company's control room operators to have the visibility, control, and optimization of distributed energy resources on the grid that is needed to make the most of those assets in a cost-effective way. With DERMS technology, the Company will have the foundational tools necessary to implement programs such as use of DER to address local and temporal grid needs (sometimes referred to as a "virtual power plant") and flexible interconnections.

System Resiliency

Q. Why is system resiliency a category of investment that is important to protect the interests of customers?

A. As discussed in the testimony of CL&P's Leadership Panel, the Company is proposing that PURA approve a multi-year rate plan that would support implementation of a targeted system-resiliency plan with an incremental capital budget of approximately $150 million, allocated across the Company's three operating regions. This targeted system-resiliency plan is discussed in Exhibit CLP-TSP-3, at pages 113 to 120.

Resiliency investment protects customer affordability in three distinct ways. First, the value of resiliency is not limited to the rare, catastrophic storm. While Connecticut has experienced four once-in-a-generation storms in the past fifteen years, the larger and more persistent driver of customer harm is the steady cadence of smaller storms. The system experiences approximately 35 to 45 storm-active days each year (days with 100 or more outage events), and these days account for over 50 percent of the total

customer-minutes of interruption (CMI) experienced system-wide, despite representing only about 12 percent of calendar days. Hardening investment reduces customer impact across this entire spectrum of events, not solely the catastrophic storms.

Second, hardening reduces the cost and duration of restoration even when an outage does occur. Replacing aging, substandard poles with the Company's current Class 2 standard substantially reduces the likelihood of pole failure under storm loading. Because a broken pole requires full structure replacement (a far longer and more expensive repair than re-energizing an intact line), preventing pole breakage directly reduces both restoration time and storm-restoration cost. Faster restoration and lower storm costs are themselves an affordability benefit to customers.

Third, the Company's resiliency strategy is deliberately designed to capture the great majority of the resiliency benefit at a fraction of the cost of the most expensive alternative. Rather than converting high-risk overhead corridors to underground construction, which can cost several times more, the Company is targeting spacer cable reconductoring. Spacer cable captures roughly two-thirds of the storm-performance benefit of undergrounding at approximately one-third of the cost. This cost-effective approach allows the Company to extend resiliency benefits to far more customers per dollar invested, which is squarely in the interest of customer affordability.

Q. Is there a difference between "system reliability" and "system resiliency" for the purpose of CL&P's capital plan and 5-year TSP Plan?

A. Yes. PURA has previously recognized that, for the electric sector, "reliability" is defined as the ability of the power system to deliver electricity in the quantity and quality demanded by users. Reliability is generally measured by the standard interruption indices defined in IEEE Standard 1366. In practical terms, "reliability" means the lights are on in a consistent manner, a largely binary view of system performance in which the system is either functional or failed. The indices typically used to measure reliability (SAIDI, SAIFI, and CAIDI) capture how often customers are interrupted and for how long.

As defined by the National Infrastructure Advisory Council, infrastructure "resilience" is the ability to reduce the magnitude and duration of disruptive events. The effectiveness of a resilient infrastructure depends on its ability to anticipate, absorb, adapt to, and rapidly recover from a potentially disruptive event. Resilience is therefore a broader concept than reliability. At its core, "reliability" addresses whether customers have power, while "resiliency" broadens the inquiry to the full set of factors that influence whether a customer loses power, for how long, and how quickly service can be restored. Reliability is thus a subset of resilience, and resilience is achieved through a combination of mitigation and recovery.

This distinction matters for the Company's capital plan and five-year TSP Plan because customer harm is driven by both ends of the weather spectrum. On normal "blue sky"

days, performance is governed primarily by asset condition, and traditional reliability tools (proactive equipment replacement, reclosing devices, and distribution automation) are highly effective and continue to deliver substantial customer benefit. The majority of total customer impact, however, occurs on storm-active days: over 50 percent of total CMI occurs on the 35 to 45 days each year with 100 or more outage events. On those days, the damage is predominantly physical and widespread, with many faults occurring simultaneously across the system. Reducing that customer impact depends on limiting the physical damage at its source, which is the purpose of resiliency investment, or system hardening, the focus of the targeted plan described in this testimony.

Q. What type of investment is considered "mitigation" for purposes of enhancing system resiliency?

A. System "hardening" is the primary means of mitigation. Hardening refers to physically changing the infrastructure to make it less susceptible to damage, improving the durability and stability of the system so that it can better withstand hurricanes, wind and weather events, and other stresses on the infrastructure. This is distinct from recovery measures, which do not prevent damage but rather enable the system to continue operating despite damage and promote a rapid return to normal. Preparation for recovery, including advanced contingency planning, interagency coordination, and crew training, likewise supports an effective restoration process.

Different storm types impose different threats, and effective mitigation must account

for all of them: tropical storms and hurricanes bring high winds together with heavy rainfall and, along the coast, rivers, and low-lying areas, storm surge and flooding; tornadoes bring extreme localized winds; and winter storms load overhead equipment with snow and ice and can prevent switches and other devices from operating.

For the overhead distribution system, the principal mitigation measures, in increasing order of protection and cost, are:

Stronger poles. Replacing substandard wood poles with the Company's current Class 2 (or stronger) standard increases the structure's ability to withstand wind and vegetation loading and reduces the likelihood of pole breakage, the failure mode that drives the longest and most costly restorations. Today, approximately 76 percent of the Company's poles are below the current standard.

Covered (tree) wire. Covered conductor adds an insulating layer that prevents incidental tree and limb contact from causing a fault, reducing outages in vegetated corridors relative to bare wire.

Spacer cable. Spacer cable replaces bare overhead wire with fully insulated, bundled conductors suspended from a steel messenger wire by non-conductive spacers. It provides both electrical protection (insulation prevents tree contact from faulting) and mechanical protection (the messenger absorbs and distributes impact loads, the bundled geometry reduces horizontal exposure to falling debris, and the spacers buffer impact energy between conductors). Spacer cable is approximately 62 percent more effective

than bare wire at preventing storm outages in high tree-conflict zones and captures roughly two-thirds of the storm-performance benefit of undergrounding at about one-third of the cost.

Aerial cable. Fully insulated aerial cable provides a further increment of mechanical and electrical protection for overhead corridors where conditions warrant.

Undergrounding. Relocating lines underground eliminates exposure to wind and trees almost entirely and provides the highest level of storm protection. However, it is also the most expensive option, costing multiples more than spacer cable. In addition, underground faults take substantially longer to locate and repair. For these reasons undergrounding is reserved for locations where its cost can be justified, while spacer cable serves as the Company's primary hardening tool for high-risk rural and suburban corridors.

Q. What is the Company proposing in this proceeding for a resiliency framework?

A. The allocation of the resiliency budget and the number of priority zones by operating division is shown in Exhibit CLP-TSP-3, at 142.

Q. What would be the benefit of implementing this Resiliency Plan?

A. The Resiliency Plan is designed as an equity-focused, high-impact approach that delivers measurable benefits for customers and communities. The plan would harden approximately 105 miles of overhead line by reconductoring bare wire, reaching approximately 60,000 customers in 68 towns across the state and protecting

approximately 90 critical facilities, including medical and emergency services. Its geographic reach is deliberately broad to ensure an equitable distribution of benefits.

The plan also produces quantifiable performance and economic benefits. By hardening these zones, the Company projects annual savings of approximately 12.4 million customer-minutes of interruption. Valued at the Company's $3-per-customer-minute estimate of the value of lost load, this represents approximately $37.1 million per year in avoided customer-borne costs. In addition, the plan improves restoration capability: approximately 40 tie reclosers are part of the resilience plan, enabling faster automated switching and restoration when outages do occur.

Finally, the plan is structured around an explicit customer-centric approach: it prioritizes the highest Storm-CEMI locations first, ensuring that the most storm-burdened customers are addressed before the plan optimizes its remaining zones for maximum statewide reliability benefit.

Advancing the Grid

Q. Why does the Company include a plan for Advancing the Grid in the filing?

A. The Advancing the Grid plan is designed to focus spending on technologies that support superior operational performance; assist in meeting policy objectives such as DER integration and clean energy advancement; and increase use of AI/ML innovations. These advances are needed to bring the CT distribution system into the future to meet customers' needs in a cost-effective manner.

Q. What investments is the Company proposing in the Advancing the Grid plan and what are the benefits of those investments?

A. The Advancing the Grid plan investments include the following:

Sensor Strategy – Targeted use of advanced line sensor technology to transform the Eversource distribution system from a reactive restoration model to predictive, sensor-enabled system that proactively protects the public, identifies degrading assets before failure, and improves restoration performance during major events.

DERMS Demonstration – Demonstrate the value proposition of advanced DERMS capabilities, including (1) use of DER to increase system efficiency and reduce line losses; (2) integration of multiple types of DER in a microgrid application for critical load; and (3) investigation of lower cost approaches to communication and control of stand-alone solar and storage facilities integrated into the Company's centralized DERMS system.

Adaptive Protection - Adaptive protection preserves safety and reliability during abnormal or reconfigured system states by continuously adapting protection settings in real time.

Communications - Distribution External Routable Connectivity ("dERC") - Distribution External Routable Connectivity (dERC) will update obsolete equipment and maintain communication between substations and Supervisory Control and Data Acquisition ("SCADA").

Analytics Platform - Allows for massive-scale data processing (billions of records) with secure data storage for automated data cleaning, Generative Artificial Intelligence ("GenAI") and Large Language Model ("LLM") tool development, and machine learning.

Integrated Distribution Planning - In Docket No. 21-05-15RE03 PURA laid out its vision for Integrated Distribution System Planning ("IDSP") ("Authorities Version") to which the Companies have provided their version of the IDSP with reduced scope, but still maximizing value in a cost-efficient manner and includes new Circuit Planning Capabilities to manage planning models and Advanced Forecasting Tools to move this topic forward.

Integrated Energy Planning - Develop an integrated energy planning tool capabilities with learnings from other jurisdictions to allow coordinated, gross company, planning between gas and electric.

Protection & Control - Virtual Protection replaces traditional, hardware-heavy substation devices with software applications running on standardized, virtualized servers to reduce physical equipment, lower maintenance costs, and enable more flexible, resilient grid management.

Shared Hosting for Advancement of Renewable Energy (SHARE) Program – Innovative approach to resolving DER substation saturation and queue stagnation due to the current cost-causation principle for DER interconnections and accompanying

free-ridership issues. This is particularly a concern in areas of the system with high DER growth potential and insufficient electrical infrastructure to accommodate large-scale DER due to lack of native load. The Program would study DER at groups of interdependent substations and develop group solutions to 1) integrate the stalled DER safely and reliably within a fixed timeframe, 2) equitably allocate group solution costs between current and future DER and load customer, who benefit from increased capacity and reliability, 3) solve the free-ridership problem by instituting a fixed $/kW fee for current group members and all future DER that would subscribe to the solution, 4) provide cost-certainty for current and future developers, and 5) enable future DER growth by providing additional capacity due to use of standard-size equipment.

Q. Would you please describe the Company's planning model for developing investments in relation to the "Advancing the Grid" program component?

A. Yes. The 5-Year TSP Plan builds on the Company's expertise and data-driven strategies, as well as knowledge of engineering and operations and data analytics. The Company is also developing "Advancing the Grid" as a complete program that does more to advance cost-effective, innovative solutions that make the Company more predictive, more optimized and supports more clean energy integration into the grid. Thus, "advancing the grid" is about taking the distribution grid and really pushing it to the next level in terms of more communication and control, along with sensors installed prevalently across the grid, enabling the Company to have "eyes" on the grid from substation to the end of the line, which will allow the Company to help predict problems

before those problems happen. It's also about analytics and AI because there are so many resources now available through "machine learning." The Company needs these foundational platforms to be able to take these analytics to help undertake system planning and forecasting, which is the reason that the Company is investing in communications and control analytics.

Lastly, the Company is working to determine how does it enable more DER integration on the grid and how can it be more cost effective. The Company is proposing the "Share Program," and the Share Program looks at new ways to make more cost-effective integration of large-scale solar resources onto the grid. The Company is also looking at a DERMS demonstration, including more technology to make the grid more operationally DER aware.

Q. What other information is delineated in Exhibit CLP-TSP-3?

A. Other information discussed in Exhibit CLP-TSP-3 includes the following areas:

- ⇒ Non-Wires Solutions Framework (Slides 96-100).
- ⇒ Battery Storage NWA Projects for Substation Capacity Relief (Slides 101-106) [from Docket No. 22-06-05]
- ⇒ Distributed Energy Resource Management System ("DERMS") (Slides 108)
- ⇒ Communications (Slides 109-110)
- ⇒ Vegetation Management (Slides 111-112)

V. Measuring System Performance and Investment Benefits

Q. Please identify the Company's proposed metrics for assessing system performance under the proposed capital plan and five-year TSP Plan.

A. As discussed above, the goals of the Company's capital plan and five-year TSP Plan is to move towards a highly reliable, resilient modern electric distribution grid. To promote transparency and measure the Company's success in achieving the objectives outlined in our testimony, the Company proposes to track and report two System Reliability performance incentive mechanisms ("PIMs") with historical performance-based benchmarks and incentives/penalties during the PBR term: (1) Blue-Sky System Average Interruption Duration Index ("SAIDI") and (2) Blue-Sky System Average Interruption Frequency Index ("SAIFI"). The Company also is proposing a Customer Reliability PIM that measure the combined number of repeat customers for both Customers Experiencing Multiple (5+) Interruptions ("CEMI-5"); and Customers Experiencing Long Interruption Durations (6+ hours) ("CELID-6").

Q. How do the System and Customer Reliability PIMs complement and support the Company's PBR Plan?

A. The implementation of meaningful performance metrics simply furthers the transparency and effectiveness of the PBMRP. Performance metrics provide the Company with the focused objective of creating benefits and value for customers through the targeted achievement of specific goals and outcomes.

CL&P employs a team of dedicated staff with a strong commitment to providing safe and reliable electric service to its customers in Connecticut. The Company is proud of

its ongoing, rigorous efforts to ensure delivery of electric service that is reliable and resilient. As described above, the Company has performed a holistic assessment of the system and identified the need to ramp up programs that address asset health on a more proactive basis, given the age and condition of the system and the increasing demands placed on its aging infrastructure. The proposed Five-Year TSP Plan is intended to address these needs and improve system reliability and resiliency. Therefore, the Company thoroughly recognizes that it is important to put metrics in place to demonstrate performance improvements over the term of its PBMRP to demonstrate achievement of these objectives.

The proposed reliability PIMs provide insights into the Company's reliability performance from both a system and customer perspective. SAIDI and SAIFI measure the Company's system wide reliability in terms of interruptions in service and 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 Company's proposed Customer Reliability PIM, which is based on the average number of repeat CEMI-5 and CELID-6 customers, focuses on reliability from customer-center perspective and seeks to assess whether specific customers are experiencing multiple service interruptions or prolonged service interruptions in consecutive years. The goal of these PIMs is to encourage the Company to not only improve overall system reliability but focus on reducing the likelihood that the same customers experience several or prolonged interruptions in

service in consecutive years.

The Company's proposed set of reliability PIMs are designed to ensure that the Company maintains its high service quality standards during the PBMRP term and provide incentives to the Company to invest in manner that cost efficiently benefits customers through improved reliability and resiliency.

Q. Please describe the Company's proposed SAIDI PIM.

A. SAIDI measures the average number of minutes of interruption experienced by all customers. SAIDI is calculated as SAIFI multiplied by the Customer Average Interruption Duration Index ("CAIDI"). Accordingly, SAIDI performance reflects the combined impact of the frequency of interruptions and their duration.

The Company proposes to report on Blue-Sky SAIDI with performance measured annually against a fixed five-year historical average and standard deviation, calculated using the Institute of Electrical and Electronics Engineers ("IEEE") methodology and excluding planned outages[5] and major event days, as defined in IEEE 1366-2012.

Q. Please describe the Company's proposed SAIFI PIM.

A. SAIFI measures the average number of sustained interruptions experienced by all customers. SAIFI equals the number of customers interrupted divided by the number of customers served.

5 Planned outages are outages where CL&P provides pre-notification for an upcoming outage. Examples of planned outages may include temporary service interruptions during system upgrades.

The Company proposes to report on Blue-Sky SAIFI with performance measured annually against a fixed five-year historical average and standard deviation, calculated using the IEEE methodology and excluding planned outages and major event days, as defined in IEEE 1366-2012.

Q. How is the Company proposing to develop the PIM baselines and targets for System Reliability PIMs?

A. The Company proposes to use a fixed, five-year average with one standard deviation as the target for both System Reliability PIMs, i.e., SAIDI and SAIFI. The Company proposes to calculate the five-year average and standard deviation based on the most recent five years prior to the start of the PBR term (2022-2026). The PIMs will allow PURA and stakeholders to assess whether the Company is maintaining system reliability during the PBR term. The Company will calculate the PIM baseline and target once data for 2026 is available.

For illustrative purposes, if the Blue-Sky SAIDI PIM was based on 2021-2025 performance, the five-year average baseline would be 71.1 minutes and the standard deviation would be 3.7, making the target 74.8. Similarly, the target for the Blue-Sky SAIFI PIM, based on 2021-2025 performance, would be 0.619, based on a five-year average baseline of 0.606 and a standard deviation of 0.013. The objective of the System Reliability PIMs is for the Company's annual system performance to remain below the established targets.

Please see the tables below provide the illustrative calculation of the System Reliability PIM targets based on 2021-2025 data. The Company will calculate the actual baselines and targets once 2026 data is available.

Table 1: Illustrative Blue Sky SAIDI and SAIFI Target Calculation

	2025 YE	2024 YE	2023 YE	2022 YE	2021 YE	Avg	StDev	Penalty Threshold	Penalty Cap
Blue Sky SAIDI	77.5	69.8	68.0	69.5	70.7	71.1	3.7	74.8	78.5
Blue Sky SAIFI	0.598	0.590	0.602	0.619	0.619	0.606	0.013	0.619	0.632

Q. Please describe the Company's proposed Customer Reliability PIM.

A. The Customer Reliability PIM is a composite incentive metric with two components: (1) number of repeat CEMI-5 customers and (2) number of repeat CELID-6 customers. The Customer Reliability PIM is designed to encourage the Company to reduce the portion of customers who experience frequent or prolonged service interruptions in two consecutive years. As discussed above, as part of the proposed Advancing the Grid program, if approved, the Company will undertake targeted investments to reduce CEMI and CELID. This proposed PIM is intended to measure the Company's success in implementing the Advancing the Grid program as it relates to CEMI and CELID.

Q. Please describe how the Company proposes to measure CEMI-5 and CELID-6 for the purpose of calculating the components of the Customer Reliability PIM.

A. CEMI-5 measures the number of customers experiencing five or more sustained interruptions per year and will be calculated in accordance with the IEEE methodology, but exclude planned outages, service line outages[6] and major event days as defined by IEEE 1366-2012.

CELID-6 measures the number of customers experiencing interruptions with a duration of six hours or more per year and will be calculated in accordance with the IEEE methodology, but excludes planned outages, service line outages, and major event days as defined by IEEE 1366-2012.

Q. How is the Company proposing to develop the targets for the Customer Reliability PIM?

A. The Company proposes to use a composite, fixed, five-year average as the target for the Customer Reliability PIM. The Company proposes to calculate the five-year average based on the CEMI-5 and CELID-6 data for the most recent five years prior to the start of the PBR term (2022-2026). The target will allow PURA and stakeholders to assess whether the Company maintaining or reducing the number of customers that experience multiple or prolonged service interruptions in consecutive years. The Company will calculate the target once data for 2026 is available.

For illustrative purposes, if the Customer Reliability PIM was based on 2021-2025

6 Service line outages are interruptions solely on a customer service line. Examples of service line outages include tree limbs on a customer's property falling on the customer service line.

performance, the target for the Number of Repeat CEMI-5 and CELID-6 PIM would be 2,552.3.

The table below provides the illustrative calculation of the Customer Reliability PIM target based on 2021-2025. The Company will calculate the actual baselines and targets once 2026 data is available.

Table 2: Illustrative Customer Reliability PIM Target Calculation

	2025 YE	2024 YE	2023 YE	2022 YE	2021 YE	Avg (Target)	StDev
Average of Count of Repeat CEMI-5 and CELID-6 Customers	3303.5	2504.5	2789.5	2512.0	1651.5	2552.2	1953.1
Repeat CEMI-5 Customers	1,076	1,303	1,746	1,067	913		
Repeat CELID-5 Customers	5,531	3,706	3,833	3,957	2,390		

Q. Is the Company proposing to attach a penalty or incentive to the System and Customer Reliability PIMs?

A. Yes. The Company is proposing to establish a sliding scale penalty structure for the SAIDI and SAIFI PIMs to set its commitment to implementing the five-year TSP Plan and maintaining system reliability under the proposed PBMRP Plan. For each System

Reliability PIM, the Company proposes to allocate 35 percent of the penalty pool ($3.5 million) as discussed in the testimony of the Leadership Panel. If the Company does not meet the threshold target (one standard deviation above the five-year historic average) annually during the PBMRP term, the Company would be subject to a penalty for each year it does not meet the target. Under the sliding scale penalty structure, the penalty would start at 50 percent of the maximum penalty ($3.5 million) and escalate based on the formula below to the full penalty amount if the Company's performance is at or above two standard deviations above the five-year historic average.

(((Actual – Threshold)/(Maximum – Threshold)) x $1.75 million) + $1.75 million

Table 3, below, provides illustrative examples of potential penalties based on 2021-2025 data and hypothetical performance. As noted above, the actual baselines and targets will be based on 2022-2026 data and the Company will calculate the benchmarks once 2026 data is available.

Table 3: System Reliability PIMs Penalty Structure

SAIDI (Target 74.8)[7] (Cap 78.5)	SAIFI Targets (Target 0.619) (Cap 0.632)[8]	Penalty Level
74.8	0.619	50% ($1.75 million)
75.5	0.621	60% ($2.1 million)
76.7	0.625	75% ($2.625 million)
78.5 or greater	0.632 or greater	100% ($3.5 million)

For the Customer Reliability PIMs, the Company is proposing to establish a sliding scale incentive structure. The purpose of the PIMs are to encourage the Company to exceed core service obligations and address specific customer multi-year reliability challenges. Accordingly, the Company proposes an incentive only PIM structure, consistent with PURA's Revised Straw Proposal in Docket No. 21-05-15RE02, to encourage the Company to reduce the number and percentage of customers experiencing several or prolonged service interruptions in consecutive years.

The Company proposes a maximum incentive for the Customer Reliability PIM equivalent to 30 percent of the exogenous cost threshold ($3 million) as discussed in Exhibit CLP-ELP-1. If the Company is able to exceed the threshold target for the composite metric annually during the PBR term, the Company would begin to receive an incentive for each year. Under the sliding scale incentive structure, the Company

[7] Values rounded to nearest one decimal place for presentation purposes.
[8] Values rounded to nearest three decimal places for presentation purposes.

would start to receive 50 percent of the maximum incentive ($1.5 million). The incentive amount would then escalate based on the formula below up to the maximum incentive amount if the Company's performance is at or better than one standard deviation below the five-year historic average.

$$(((\text{Actual} - \text{Threshold})/(\text{Maximum} - \text{Threshold})) \times \$1{,}500{,}000) + \$1{,}500{,}000$$

Below is a table that provides illustrative examples of potential incentives based on 2021-2025 data. As noted above, the actual targets will be based on 2022-2026 data and the Company will calculate the benchmarks once 2026 data is available.

Table 4: Customer Reliability PIM Incentive Structure

Average Count of Repeat CEMI-5 and CELID-6 Customers[9]	Incentive Level
2,552.2	50% ($750,000)
2,252.7	75% ($1.125 million)
1,953.1	100% ($1.5 million)

Q. Are the proposed System and Customer Reliability PIMs consistent with PURA's Proposed Final Decision related PBR metrics in Docket No. 21-05-15RE02?

A. Generally, yes. In its Proposed Final Decision, PURA proposed adopting penalty PIMs based on Blue-Sky SAIDI and Blue-Sky SAIFI calculated based on the IEEE methodology, and incentive only composite metric based on CEMI-5 customers,

[9] Values rounded to nearest one decimal place for presentation purposes.

CEMI-5 Repeat Customer Percent, CELID-6 customers, and CELID-6 Repeat Customer Percent (Docket No. 21-05-15RE02, Proposed Final Decision at 33-34, 38-39). While the Company proposal includes some differences from the Proposed Final Decision, the Company's proposal is substantially based on the general methodology discussed in PURA's Proposed Final Decision.

The proposed Blue-Sky SAIDI and Blue-Sky SAIFI are calculated based on five-year historic average using the IEEE methodology, excluding major event days, but also planned outages. The Company also proposed penalty only Blue-Sky SAIDI and Blue-Sky SAIFI metrics triggered when annual performance exceeds one standard deviation above the fixed five-year historical average. The Company, however, proposes to escalate the penalty once the threshold is met up to a maximum penalty for performance that exceeds two standard deviations above the baseline.

Similarly, the proposed Customer Reliability PIM is a composite incentive-only metric consistent with the Proposed Final Decision in Docket No. 21-05-15RE02; however, the Company proposes that the composite metric be based on the average number of repeat CEMI-5 and CELID-6 customers. A metric based on dividing the number of repeat CEMI-5 and CELID-6 customers by the number of unique CEMI-5 and CELID-6 customers, as proposed in Docket No. 21-05-15RE02, could have unintended consequences, including rewarding the Company if the number of unique CEMI-5 and CELID-6 customers increases without reducing the number of repeat CEMI-5 and CELID-6 customers. The proposed composite metric based solely on number of repeat

CEMI-5 and CELID-6 customers; however, encourages the Company to reduce the likelihood a customer would experience multiple or prolonged outages in consecutive years.

The Company will calculate CEMI-5 and CELID-6 in accordance with the IEEE methodology, except the Company proposes to exclude major event days, planned outages, and service line outages. While the Company proposes that the targets for the Customer Reliability PIMs be based on the five-year historic average, consistent with the Proposed Final Decision, the Company proposes triggering incentives if actual performance is at or below the five-year historic average. Specifically, the Company proposes that it will only receive 50 percent of the maximum inventive once it achieves the target performance but is eligible to receive a higher incentive based on a sliding scale for exceeding threshold performance up to a maximum incentive of $1.5 million per PIM for performing at least one standard deviation below the five-year average.

VI. Compliance with PURA's Decision on Reliability and Resiliency Frameworks

Q. Would you please review the premise and framework of PURA's Decision in Docket No. 17-12-03RE08?

A. Yes. PURA initiated Docket No. 17-12-03RE08 on June 18, 2020, for the stated purpose of "examin[ing] existing reliability and resilience programs in Connecticut and other jurisdictions, and to develop frameworks to enhance the cost effectiveness of reliability and resilience investments moving forward." (Decision, Docket No. 17-12-03RE08, at 2). Accordingly, in its Decision, dated August 31, 2022, PURA established

reliability and resilience frameworks by which the electric distribution companies "must plan and implement their reliability- and resilience-based capital programs." (Id. at 1). PURA further directed the Company "to use [the Reliability and Resiliency Frameworks] in developing and submitting reliability and resilience program plans for PURA approval in its next general rate proceedings. (Id.).

Q. What are the compliance requirements that PURA's Decision in Docket No. 17-12-03RE08 set for Eversource in this general rate proceeding?

A. PURA's Reliability and Resiliency Framework directed the EDCs to present a Reliability Plan that *plans* for an average five (5) percent reduction in the SAIDI and SAIFI values (blue-sky conditions) during the rate plan, if PURA ultimately directs through a rate case decision the adoption of a Reliability Plan and budget that correspond to the *maintenance* of current performance (i.e., no budget earmarked toward incremental reliability improvements), then the reliability performance target would become the equivalent of the rolling four-year average SAIDI and SAIFI from the test year (with the Conn. Gen. Stat. §16-244i(d) backstop). As stated, the purpose of the plan that considers a five percent reduction in SAIDI and SAIFI is to enable PURA to compare an investment plan with a standardized metric or set of metrics. In other words, as envisioned by PURA in Docket No. 17-12-03RE08, this five percent reliability reduction parameter is not an implementation directive from PURA; rather, it is a standardized baseline to enable PURA and others to evaluate a company-specific plan. A company-specific plan will consider reliability needs, customer cost, and other factors. The decision in Docket No. 17-12-03RE08 states that the five-percent

reliability improvement plan is an evaluation too that would be included in any reliability plan filed consistent with PURA's framework. (Docket 17-12-03RE08, at 43, fn.16).

Further, PURA's Decision in Docket No. 17-12-03RE08 directed that an initial submission of each required framework for PURA review and approval would be included in the Company's next general rate case required pursuant to Conn. Gen. Stat. § 16-19a. Other directives from PURA's Decision in Docket No. 17-12-03RE08, include the following:

Order No. 3, at p. 94-95.

> The EDCs shall include in its first Reliability Plan submission submitted in its next general rate case pursuant to the Reliability Framework herein, a report on the capabilities to track momentary outages, and plan for developing the capability to track such. The plan for developing the capability must include an estimated cost to develop the capabilities.

In the Company's rate filing, the Company has included a proposal to implement Advanced Metering Infrastructure, which is a necessary prerequisite to measuring momentary outages. This proposal, including implementation details and costs, is presented in Exhibit CLP-AMI-3 (Benefit Cost Analysis for Potential Deployment of Advanced Metering Infrastructure). In this exhibit, the Company explains that measuring and analyzing reliability performance is a critical activity to ensure the Company makes cost-effective improvements in the service provided to customers. Using information on the historical frequency and duration of outages at all locations

on the grid, the Company identifies investments that maximize reliability. Improvements in the accuracy and effectiveness of reliability analysis resulting from the availability of AMI data have the potential to deliver meaningful benefits to the value of distribution system investments. Currently, it is a manual and time-consuming process to analyze the customer benefit of distribution automation schemes. Engineers use historical data to optimize device location, but it is difficult to track the actual benefit customers experience based on when switch events occur in the field. Integration of AMI data into the Outage Management System, in coordination with data from the Company's Energy Control System ("ECS"), will enable engineers to better evaluate the reliability improvement of distribution automation switches to inform improved decisions going forward. The use of AMI data will also improve reliability analysis and decision making through measurement of momentary outages.

Currently, the Company tracks a sustained customer outage as loss of supply lasting five minutes or longer. These shorter duration events are increasingly impactful for customers. Deployment of devices that automatically isolate faults and refeed unaffected sections has had a significant benefit in terms of averting sustained outages but each of these operations results in momentary outages for large numbers of customers. Using AMI data, the Company will be able to track each time a customer has an outage lasting less than five minutes. This will enable calculation of the industry-standard measure of the frequency of momentary outages, momentary average interruption frequency index ("MAIFI"). This information will enable prioritization of

measures to reduce momentary outages, including mitigations such as equipment selection and operating guidelines for distribution automation schemes. Exhibit CLP-AMI-3, Section IX Appendix, provides a list of the Necessary AMI Infrastructure and costs associated with this achieving this benefit.

Order No. 5, p. 95

> In its next general rate case, each EDC shall submit its portfolio of reliability programs and resilience programs in accordance with the Reliability Framework and Resilience Framework implemented herein and as outlined in Section II.B.5.a.i., Initial Submissions

The Company has fulfilled this requirement in Exhibits CLP-TSP-1, CLP-TSP-2 and CLP-TSP-3.

Order No. 9, p. 95

> The EDCs shall include in its Reliability and Resilience Frameworks the following information: a. Information pertaining to companion Equitable Modern Grid Programs as described in Section.II.B.7.a., Integration with Other Equitable Modern Grid Initiatives.
>
> Information demonstrating how the frameworks align with IIJA's program priorities and the steps the EDC has taken to identify and seek funding from those programs as described in Section.II.B.7.b., Alignment with Federal Funding.

The Company has fulfilled this requirement in Exhibits CLP-TSP-1, CLP-TSP-2 and CLP-TSP-3. The Company's application to obtain funding from the Infrastructure, Investment and Jobs Act (2021) was not granted by the U.S. Department of Energy.

Order No. 13, at p. 96.

> In the Company's next general rate case submitted pursuant to Conn. Gen. Stat. § 16-19a after such study is completed, the Company shall incorporate into the Reliability and Resilience Frameworks the results from its Climate Change Vulnerability Study as described in Section II.B.8.b., Prospective Modeling of Climate Change.

The Company has fulfilled this requirement in Exhibit CLP-TSP-4 (Climate Vulnerability Study, March 2025).

VII. Conclusion

Q. What are the specific objectives that PURA outlined in its Decision in Docket 17-12-03RE08 for the Reliability and Resiliency Framework?

A. At pages 39-40 of PURA's Decision in Docket No. 17-12-03RE08, PURA outlined the following objectives for its Reliability and Resiliency Framework. These objectives are fulfilled by the Company's comprehensive 5-Year TSP Plan and presentation in Exhibits CLP-TSP-1, CLP-TSP-2 and CLP-TSP-3.

Improve, or at a minimum maintain top-quartile, system reliability performance in blue-sky conditions.

This objective acknowledges that the maintenance of first quartile reliability performance, defined as a performance better than 75 percent of other electric utilities in the country, is a dynamic target dependent on the performance of other utilities. Nonetheless, differences in a utility's own performance are measurable and discernable from year-to-year; although, annual variations in operating conditions must be accounted for in subsequent evaluations. Previous performance of the individual EDC can serve as a baseline off of which to establish quantifiable targets moving forward.

Improve system reliability and resilience against Major Storms in gray-sky conditions. This objective includes minimizing the frequency and duration of damages and outages due to Major Storms classified as Event Level 5 or 4 emergencies. This objective requires the demonstration and quantification, through analysis, of clearly

defined connections between utility programs and corresponding reliability and resilience benefits. Specific metrics must be established to assess whether reliability and resilience programs targeted to enable the distribution system to withstand and recover from gray-sky conditions are performing as designed.

Improve system resilience against Major Storms in black-sky conditions. This objective includes minimizing the frequency and duration of damage and outages (and the corresponding restoration and recovery timelines) due to Major Storms classified as Event Level 1 – 3 emergencies. This objective requires the demonstration of clearly defined connections between utility programs and resilience benefits, as well as a good faith effort to quantify those benefits – particularly as methodologies and industry best practices emerge and evolve. Specific metrics must be established to assess whether resilience programs are performing as designed, even if such assessments must rely on simulated data for a counterfactual or sensitivity analysis.

Identify system and customer vulnerabilities to climate change and prioritize delivering increased resilience. This objective requires the identification of electric distribution system and customer vulnerabilities to climate change, particularly due to the increasing intensity and frequency of weather events.

Maximize benefits realized by, and the return on investment to, customers. This objective requires the identification and adoption of methods to manage costs and to prioritize, or re-prioritize on a rolling basis, programs to achieve maximum benefits for customers and the public at large. As such, this objective requires the identification and continued refinement of a methodology that quantifies the benefits, and avoided costs, that accrue to ratepayers from different types of reliability and resilience measures. In furtherance of this objective, there must be an effort to differentiate between and within customer classes when evaluating proposed resilience measures to ensure that societal and customer benefits are not masked, and to ensure a balance between cost considerations and minimization of outage duration for the longest-out customers, grid edge customers, medical protection customers, and other vulnerable populations.

Establish minimum staffing standards as a resilience measure and identify the effect of such standards on staffing needs in blue-sky, gray-sky, and black-sky conditions. This objective requires that minimum staffing standards be considered as an applicable resilience measure in formulating each EDC's Resilience Framework, as well as the evaluation of how such standards impact other reliability and resilience programs, including a reduction in the reliance on mutual aid resources and other out-of-state contractor resources.

Improve grid flexibility. This objective requires each EDC, on a continual basis, to identify and integrate other Equitable Modern Grid Initiative programs into its reliability and resilience program planning to leverage potential synergies, assist in

prioritization of certain resilience programs, and avoid duplicative or stranded costs.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX

Eversource Targeted System Performance Plan

List of Acronyms

ABR	Automatic Bus Restoral
AC	Air Conditioner
ADMS	Advanced Distribution Management System
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
ANIM	Animal
API	Application Programming Interface
APS	Adaptative Protection System
ASR	Aggregation Services Routers
AWC	Area Work Center
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
BEA	Bureau of Economic Analysis
BESS	Battery Energy Storage System
BTM	Behind-the-Meter
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CAT	Catastrophic
CELID	Customers Experiencing Long Interruption Duration
CELID-6	Customers Experiencing Long Interruption Durations (6+ hours)
CEMI	Customers Experiencing Multiple Interruptions
CEMI-5	Customers Experiencing Multiple (5+) Interruptions
CHP	Combined Heat and Power
CI	Customers Interrupted
CIRED	International Community on Electric Distribution
CL&P	The Connecticut Light and Power Company
CMI	Customer Minutes Interrupted
Cu	Copper
D ROW	Distribution Rights-of-Way
DA	Distribution Automation
DB	Direct Buried
DER	Distributed Energy Resource
dERC	Distribution External Routable Connectivity
DERMS	Distributed Energy Resources Management System

DFR	Dynamic Fault Recorder
DG	Distributed Generation
DMS	Distribution Management System
DOT	Department of Transportation
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSEM	Distribution System Engineering Manual
DSPG	Distribution System Planning Guide
EDC	Electric Distribution Company
EE	Energy Efficiency
ENGO	Edge of Network Grid Optimization
EOL	End-Of-Life
EPRI	Electric Power Research Institute
EPS	Electric Power System
EQUP	Equipment
ERC	External Routable Communication
ESC	Eversource Energy Services Company
ESS	Energy Storage System
ETR	Estimated Time of Restoration
ETT	Enhanced Tree Trimming
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FR	Failure Rate
FRAD	Frame Relay Access Devices
FTE	Full-Time Employee
FTM	Front-of-the-Meter
GenAI	Generative Artificial Intelligence
GFOV	Ground Fault Overvoltage
GIS	Geographic Information System
GSCF	Grid Services Compensation Fund
GW	Gigawatt
HMP	High Melting Point
IBR	Inverter-Based Resource
ICE	Interruption Cost Estimate
IDSP	Integrated Distribution System Planning
IEEE	Institute for Electrical and Electronics Engineers
IML	Instrumenta Mechanik Labor (manufacturer name)
IP	Internet Protocol
ISO-NE	Independent System Operator – New England
kV	Kilovolt

LED	Light-Emitting Diode
LiDAR	Light Detection and Ranging
LLM	Large Language Model
LROV	Load Rejection Overvoltage
LRP	Long Range Plan
LTC	Load Tap Changer
LTI	Long-Term Health Index
LTNG	Lightning
MBI	Months Between Interruptions
MH	Manhole
ML	Machine Learning
MPLS	Multiprotocol Label Switching
MVA	Megavolt-Ampere
MW	Megawatt
MWh	Megawatt-Hour
NTA	Non-Transmission Alternative
NWA	Non-Wires Alternative
NWS	Non-Wires Solutions
O&M	Operation and Maintenance
OH	Overhead
OMS	Operations Management System
OPM	Outage Prediction Model
OVLD	Overload
PBR	Performance-Based Rates
PILC	Paper Insulated Lead Covered
PIM	Performance Incentive Mechanism
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PoF	Probability of Failure
POI	Point of Interconnection
PQ	Power Quality
PTNF	Patrolled Nothing Found
PTX	Power Transformer Expert System
PURA	Connecticut Public Utilities Regulatory Agency
PV	Photovoltaic
RAM	Rate Adjustment Mechanism
RFI	Request for Information
RFP	Request for Proposal
RIMS	Regional Input-Output Modeling System
ROI	Risk of Islanding
ROW	Right-of-Way

RTU	Remote Terminal Unit
RTW	Reliability Tree Work
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SHARE	Shared Hosting for Advancement of Renewable Energy
SPA	Single Pole Administrator
SSVT	Station Service Voltage Transformer
STI	Short-Term Health Index
TPTG	Transmission Planning Technical Guide
TSP	Targeted System Plan
UG	Underground
URD	Underground Residential
VHCL	Vehicle
VOLL	Value of Lost Load
VPP	Virtual Power Plant
VVO	Volt-Var Optimization
WMECO	Western Massachusetts Electric Company
WO	Work Order
XLP	Cross-Linked Polyethylene