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

MATTHEW NELSON AND MICHAEL GOLDMAN
APEX ANALYTICS, LLC

Powering Connecticut's Future
Investment & Affordability Policy

On behalf of

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

July 14, 2026

Table of Contents

I. WITNESS INTRODUCTION AND QUALIFICATIONS 3

II. PURPOSE AND SUMMARY OF TESTIMONY 10

III. THE INVESTMENT CALIBRATION FRAMEWORK 27

A. Overview 27

B. The Two Tails Are Not Symmetric 34

C. The Asymmetric Allure of Underinvestment 35

D. Case-Study Evidence — The Underinvestment Tail Materialized 37

E. National Affordability Benchmarking — CL&P Relative to Peer Utilities 45

IV. APPLICATION TO CL&P'S PROPOSED CAPITAL INVESTMENT 50

V. AFFIRMATIVE RECOMMENDATIONS 57

A. Overview 57

B. Performance-Based Multi-Year Rate Plan 59

C. Economic Development Rate 62

D. Optional Residential Space Heating Rate 67

E. Consumer Dividend, Structured as an S-Factor 70

VI. CONCLUSION 85

I. WITNESS INTRODUCTION AND QUALIFICATIONS

Q. Please introduce the witnesses sponsoring the Investment & Affordability Policy testimony.

A. The Investment & Affordability Policy testimony is sponsored by Matthew Nelson and Michael Goldman of Apex Analytics, LLC.

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

A. My name is Matthew Nelson. My business address is 1717 Bluebell Ave., Boulder, CO 80302, and I am testifying on behalf of the Connecticut Light and Power Company d/b/a Eversource Energy ("CL&P," "Eversource," or the "Company").

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

A. I am a Principal at Apex Analytics, LLC ("Apex"), an energy services consulting firm that provides strategic input, evaluation support and research for energy industry stakeholders. In my role at Apex, I lead the team on Regulatory Policy with a focus on utility safety, system planning, consumer protection, competitive electricity markets, rate structures and transmission development.

Q. Please summarize your education and professional experience.

A. I graduated from Stonehill College in 2001 with a Bachelor of Arts degree in Economics and Mathematics. In 2002, I earned a Master of Arts degree in Economics from Tufts University. From 2002 to 2012, I worked for the

Commonwealth of Massachusetts, including four years at the Massachusetts Department of Public Utilities ("MDPU") as an Economist in the Electric Power Division. From 2012 to 2016, I worked for Eversource Energy in Massachusetts as Supervisor of Regulatory and Planning with the energy efficiency program. During my tenure, I co-authored several energy efficiency papers accepted for publication by the International Energy Program Evaluation Conference and the Association for Energy Service Professionals.

In 2016, I returned to the MDPU as the Director of the Electric Power Division, managing the staff of the Electric Power division, as well as the Regional and Federal affairs division. In that role, I provided guidance to the MDPU commission on numerous policy issues including grid modernization, energy efficiency and demand-side management programs, integration of distributed energy resources, including energy storage, storm response, the deployment of Electric Vehicle pilots, solar and net-metering issues, electric rate investigations on issues including decoupling, performance-based ratemaking, rate design, and general cost of service rate making issues. I was also directly involved in the examination of electric company filings on storm restoration and cost recovery, long-term renewable contract solicitations for offshore wind and regional and federal issues related to ISO New England. In 2019, I was

promoted from that position to Chairman of the MDPU, which is a position I held for four years, leaving state service for a role with Apex in 2023. During that time. I led the Department through the Merrimack Valley Gas Incident restoration, the COVID-19 pandemic, and the FTA's investigation into the Massachusetts Bay Transportation Agency.

In 2025, I was named to the Board of Managers for PJM Interconnection LLC, which is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of 13 mid-Atlantic states and the District of Columbia. The Board of Managers is responsible for ensuring that PJM maintains the reliability of the power grid and operates a robust, competitive and non-discriminatory electric power market, preventing any market participants from having undue influence over the operation of PJM. PJM is currently going through a rapid period of change primarily due to growth from data centers.

Q. Have you previously testified before the Connecticut Public Utilities Regulatory Authority or elsewhere on regulatory matters?

A. I have never testified before the Connecticut Public Utilities Regulatory Authority ("PURA"). I have testified before other public utilities commissions, including the New York Public Service Commission, the Colorado Public Utilities Commission, and Massachusetts Department of Public Utilities. Since January 2023, I have submitted expert testimony

in the following proceedings, among others: Atmos Gas Clean Energy Plan, Colorado Public Utilities Commission, Docket No. 23A-0632G; Key Capture Energy, New York Public Service Commission, Cases 23-E-0418 and 23-E-0419. I am also currently testifying in front of the Massachusetts Department of Public Utilities in Petition by Jen-Coat, Inc. d/b/a ProAmpac for an Investigation into the Rates and Practices by Westfield Gas & Electric Department pursuant to G.L. c. 164, §§ 58 and 59, D.P.U. 23-87 (pending).

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to my statement of qualifications, Exhibit IAP-2, I am sponsoring Exhibits IAP-4, IAP-5, IAP-6, and IAP-7, as described below. Exhibit IAP-4, titled, "Electric Utility Distribution Costs: Scoping Study on Trends, Drivers, and Possible Response Strategies," is a May 2026 study by Lawrence Berkeley National Laboratory ("LBNL") that examines national and regional trends in investor-owned utility distribution-system spending. Exhibit IAP-5, titled "Retail Electricity Price Trends and Drivers: Data Update-2026 Edition" is an April 2026 report prepared by LBNL and the Brattle Group that summarizes national and state retail electricity price trends through 2025. Exhibit IAP-6, titled "Florida Power & Light Company 2022 Annual Status Report on Storm Protection Plan Programs and Projects," is a report submitted to the Florida Public Service

Commission on May 31, 2023 that describes Florida Power & Light Company's storm-protection and system-hardening programs, its 2022 completed activities and costs, and its planned 2023 activities. Exhibit IAP-7 "RE08 Affordability Evaluation of Reliability-Related Capital Investment" is an exhibit prepared by Apex Analytics and Viridi Edge using data provided by Eversource and applies the affordability framework established in Docket No. 17-12-3RE08 to CL&P's proposed reliability-related capital investments.

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

A. My name is Michael Goldman. My business address is 1717 Bluebell Ave., Boulder, CO 80302, and I am testifying on behalf of CL&P.

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

A. I am a Principal at Apex, where I focus on regulatory strategy initiatives across New England and Northeast jurisdictions. I have advised utilities, regulators and clean energy stakeholders on rate design, affordability, distributed energy resources, energy efficiency, demand response, and grid modernization policies. My work regularly involves the development of testimony, regulatory filings, stakeholder engagement strategies, and policy recommendations for utilities, clean technology companies, commissions and government agencies.

Q. Please summarize your education and professional experience.

A. I graduated from the University of Wisconsin-Madison with a Bachelor of Arts degree in 2004. I earned a Master's degree in International Finance and Energy Policy from the Johns Hopkins University in 2008. In addition to several research and policy development internships, I accepted a position with PowerAdvocate in 2008 as an Energy Business Analyst, then joined Deloitte Consulting as a Strategy & Operations consultant in their Energy and Resources practice in 2010. From 2012 to 2021, I worked for Eversource Energy in a sequence of roles, ending with Director of Energy Efficiency, Regulatory, Planning and Evaluation for the portfolio of energy efficiency programs conducted by Eversource in compliance with its program administrator role in Massachusetts.

From 2021 to 2023, I worked for Generac Grid Services as the Director, Business Development and Regulatory Affairs, where among other policy issues, I advised clients on industry developments related to distributed energy resources, demand response, virtual power plants, electric vehicles, and distributed energy resource management systems. In 2023, I joined Apex in a consulting role working with clients on a broad range of energy industry policy for clean-energy programs, specializing in strategic advisement, program support and regulatory support. I have recently focused on the development of new rates for distributed energy

resources, working directly for two different public utility commissions and facilitating stakeholder working groups on issues such as integrated energy planning and non-pipeline alternatives. I am a frequent presenter at major industry conferences such as DistribuTECH, IEPEC, and AESP, and have been published or quoted in periodicals such as PowerGrid, Electric Light & Power, Utility Dive, and GreenTech Media.

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

A. Yes, I either provided direct testimony before PURA or provided regulatory support in Docket Nos. 17-12-03RE03, 17-12-03RE04 and 17-12-03RE05, which are all part of PURA's Equitable Modern Grid framework. In addition, I have testified before the Massachusetts Department of Public Utilities in Docket Nos. D.P.U. 15-164, D.P.U. 15-169, D.P.U. 16-178, D.P.U. 17-84, D.P.U. 18-50, D.P.U. 18-115, D.P.U. 18-119, and D.P.U. 19-120. I have also testified before the New Hampshire Public Utility Commission in DE 17-136 and IR 20-166.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring my statement of qualifications, Exhibit IAP-3.

Q. To prepare this testimony, did you obtain information, data and assistance from the Company's internal subject matter experts?

A. Yes, we did. To conduct necessary research and prepare associated analysis, we obtained information, data and assistance from several Company experts in the engineering, financial, plant accounting and regulatory areas, primarily.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of this joint testimony?

A. In this proceeding, we have been retained by Eversource to provide research, analytical support and policy guidance on the industry principles, practices and perspectives that exist in relation to customer affordability, in general, and in relation to the consideration of capital investment requirements in that context. In our business model, we do not take engagements to advocate for a particular revenue requirement or a particular dollar amount. Our testimony is more fundamentally directed at the socioeconomic, financial and political ramifications of regulatory policies that may be (or have been) implemented by regulatory commissions across the nation.

We agreed to participate in this proceeding, and to testify on behalf of CL&P, out of a concern for appropriate rate-making policy for the benefit of customers rather than advocating for specific financial outcomes for

the Company in the case. In our assessment, Connecticut was venturing down a road furthering sustained underinvestment in the distribution system that, over the long run, would inevitably lead to lost reliability and higher, not lower, costs for customers. The Investment Calibration Framework that we describe in Section III, and the documented case studies in Section III.C, are intended to show why underinvestment is the more expensive path for customers over time. Accordingly, the purpose of our testimony is to offer PURA an affordability lens that distinguishes disciplined, calibrated investment from both over-spending and under-spending. Our purpose is not to advocate for any particular level of capital expenditure and we do not.

Q. Do you expect there to be challenges raised in this proceeding simply on the basis of the size of the existing revenue deficiency?

A. Yes, we do. However, it is necessary to look deeper. This is the first Connecticut rate case in many years, coming out of a period of status quo investment. In our review, the revenue requirement is a lean compilation attached to a large core business need. Other than the cost recovery framework put forward for Advanced Metering Infrastructure ("AMI"), described in the testimony of Company Witnesses Jared A. Lawrence and Douglas P. Horton, there are no significant programs proposed in this case that sit outside the core business. Information technology build-out

and facilities programs do not drive the increase.[1] The rate-year request for facilities' operating and maintenance ("O&M") expense follows from the inflationary trends we have experienced over the last five years, rather than reflecting new discretionary programs. The primary increase arises from a need to maintain the reliability of the electric grid for the benefit of customers, which is the core obligation that CL&P has to its customers.

Second, CL&P is proposing to implement a performance-based multi-year rate plan ("PBMRP") as a necessary step to (1) support ongoing capital infrastructure needs; and (2) structure a longer-term ratemaking model that creates strong incentives for cost efficiency and stabilizes the rate changes that customers will experience over time, rather than embarking on a pattern of continued rate petitions to increase revenues in support of the necessary capital investment. In recent years, the Company has refrained from increasing its distribution infrastructure investment in Connecticut due to external pressures and the Connecticut regulatory environment, which discouraged utility infrastructure investment. The Company describes in its system engineering testimony, Exhibit CLP-TSP-1, its priorities and intentions in the coming years and the level of

[1] Facilitates O&M experienced less than a 4-percent increase and Computer Services and information Technology operating and maintenance expense was less than a 6-percent increase over the test year.

necessary investment needed to safely and reliability serve its customers, in a cost environment that has shifted sharply upward since its last rate case.

Third, in recognition that this increase in infrastructure investment comes at a difficult time for customers, our testimony does not seek to minimize that fact. This is, in many ways, one of the most challenging moments in the history of utility regulation, with circumstances where inflation is elevated, infrastructure is aging, clean energy policy is continuing to evolve, recent federal action has reduced or withdrawn support for new supply and innovation in the New England area, and the traditional ISO-NE generation market has remained stagnant. The opportunities to reduce energy costs for customers are genuinely constrained in this environment, and that constraint is compounded by national economic conditions and global events. Our testimony responds to that environment in two ways – first, by offering a framework for calibrating PURA's review of the capital plan to demonstrate the need for infrastructure investment at a measured cost (Sections III through V); and second, by pairing the investment case with concrete affordability measures (Section VII, together with the rate-design and low-income testimony of other witnesses).

Fourth, the pressure on CL&P's distribution costs is consistent with a national pattern. Recent analysis by Lawrence Berkeley National Laboratory ("LBNL") finds that utility distribution spending has risen approximately six percent per year since 2014, roughly four times the pace of the prior two decades, and that distribution-cost growth accounts for about 30 percent of the national increase in retail electricity rates, driven largely by depreciation and financing on capital and by equipment-price inflation well above the general rate of inflation. CL&P is experiencing the same forces that are raising distribution costs across the industry.[2]

Q. In your experience, is the Company asking customers to fund discretionary or ''nice-to-have'' investments in its infrastructure plan?

A. No. At its core, this is a reliability case. The revenue requirement is driven by increased capital infrastructure investment costs (depreciation and the cost of capital), storms and external cost pressures — not by a discretionary build program. The question before PURA is therefore not whether to fund optional enhancements; it is how to fund the maintenance and hardening of an aging system on which customers depend. The project-level basis for that work is presented by the Company's system-

[2] Exhibit IAP-4, "Electricity Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, at pg. 5.

planning panel; our testimony addresses the affordability frame in which PURA should evaluate it.

Q. What is the relationship between affordability and reliability?

A. In our view, affordability and reliability are not opposing objectives to be traded off against one another. The concepts of "affordability" and "reliability" are correlated and move together over the relevant time horizon. A system that is allowed to degrade does not become more affordable; it becomes less reliable and, in time, more expensive to maintain and fix.

There is a short-run appearance of tension because deferring investment will lower bills in the short run. But that appearance is precisely the affordability paradox our framework is designed to expose. Measured over the life of the assets involved, the calibrated investment path is both the more reliable and more affordable one. The remainder of our testimony develops that proposition and applies it to the case before PURA.

Q. What is the purpose of your testimony in this proceeding?

A. Against this backdrop, our joint testimony is intended to do the following:

- Define affordability as that term is actually used in Connecticut and reconcile the several definitions now in play.

- Establish a framework PURA can use to evaluate affordability in the context of CL&P's proposed capital investment program.
- Demonstrate that the Company's proposed level of investment is consistent with what I will call "calibrated investment" under that framework, providing the optimal balance between under and over-spending (as described in Sections III and IV).
- Respond to the misconception that affordability not only justifies, but requires compression of capital investment, associated cost recovery, the authorized return on equity.

Our opinion is directed at the framework for evaluating infrastructure investment for a system of CL&P's scale, and at whether the proposed plan sits within the calibrated range that the framework defines. Our opinion is not centered on the amount of investment that the Company has identified as its targeted system performance plan ("TSP"), proposed by Eversource leadership (Exhibit CLP-ELP-1).

Q. How should the Company, PURA, and the other parties think about affordability as it pertains to the Company's proposals in this proceeding?

A. Affordability is best understood as calibrating investments so that customer value is delivered at a reasonable cost. This perspective supports structured ratemaking mechanisms, such as the Company's

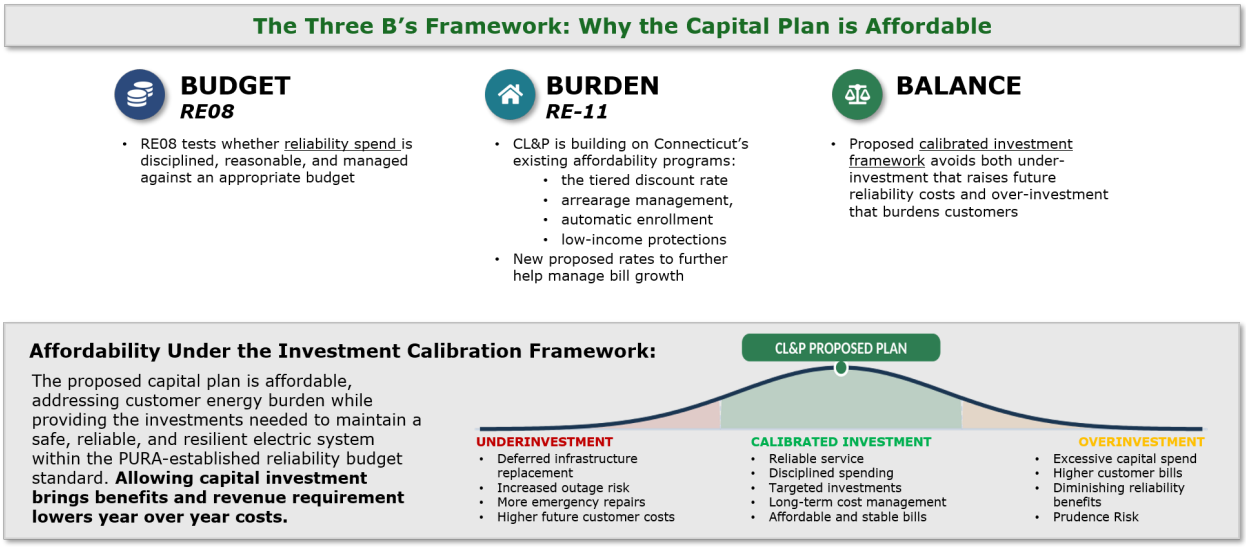
proposed PBMRP, which is designed to enable targeted, disciplined investment, while holding the Company accountable for delivering measurable benefits. Affordability should not be confused with indiscriminate spending cuts or deferred investment. Reliability is the special case that makes this caution necessary. Unlike most categories of cost, the consequences of letting reliability slip are not linear; once system performance degrades past a certain point, restoration costs, emergency response, accelerated asset failure, and the outage costs customers bear all rise steeply together. A reduction that looks affordable in the year it is booked can be the most expensive decision on the table. We develop this asymmetry in Section III of our testimony. Although reducing capital expenditures may lower costs in the short term, it can undermine reliability, raise long-term expenses and erode customer value. Ultimately, affordability is best measured by utility efficiency, i.e., not how much is spent, but whether each dollar invested yields meaningful customer benefits.

Q. What is the ‘‘Three B’s’’ framework have you developed to examine affordability lenses?

A. To evaluate the affordability of the Company’s planned distribution spending and investments, we have developed a framework to examine different affordability lenses. As shown in the figure below, this

framework is structured around the "Three Bs" (Budget, Burden and Balance) and draws on analytical frameworks developed by PURA.

Figure 1: Affordability Framework[3]



The "Budget" lens represents the Company's perspective and examines whether the Company's infrastructure plan is disciplined; whether expenditures are reasonable and well-justified; and whether investments are managed within an appropriate budgeting framework. The Budget lens also asks whether the Company is optimizing the dollars it deploys, whether investments are screened and prioritized using the Company's data; and whether predictive analytics are used as tools so that cost-effective work is undertaken appropriately.

[3] Source: Developed by Apex, 2026

The "Burden" lens represents the customer perspective and focuses on whether customer bills remain manageable and costs are allocated equitably across households.

The "Balance" lens reflects PURA's regulatory perspective and assesses whether the pace and scale of investment are appropriate, aiming to avoid both overinvestment (which can increase costs without commensurate benefits) and underinvestment (which can erode reliability, create future cost pressures, and ultimately harm customers). These three perspectives offer a practical framework for assessing affordability, recognizing both the costs of utility investment and the long-term value delivered to customers.

Each "B" maps to a construct PURA has already examined, i.e., "Budget" maps to RE08, "Burden" maps to RE11, and "Balance" maps to general ratemaking principles. Each "B" has its own tools, cost discipline, low-income customer protection and project-level prudence and performance standards. The goal of just and reasonable rates is to achieve all three at once.

Q. Which ''B'' does your testimony focus on?

A The regulator's perspective, which is Balance affordability. This is the lens that our testimony principally focuses on, and, in our view, the one

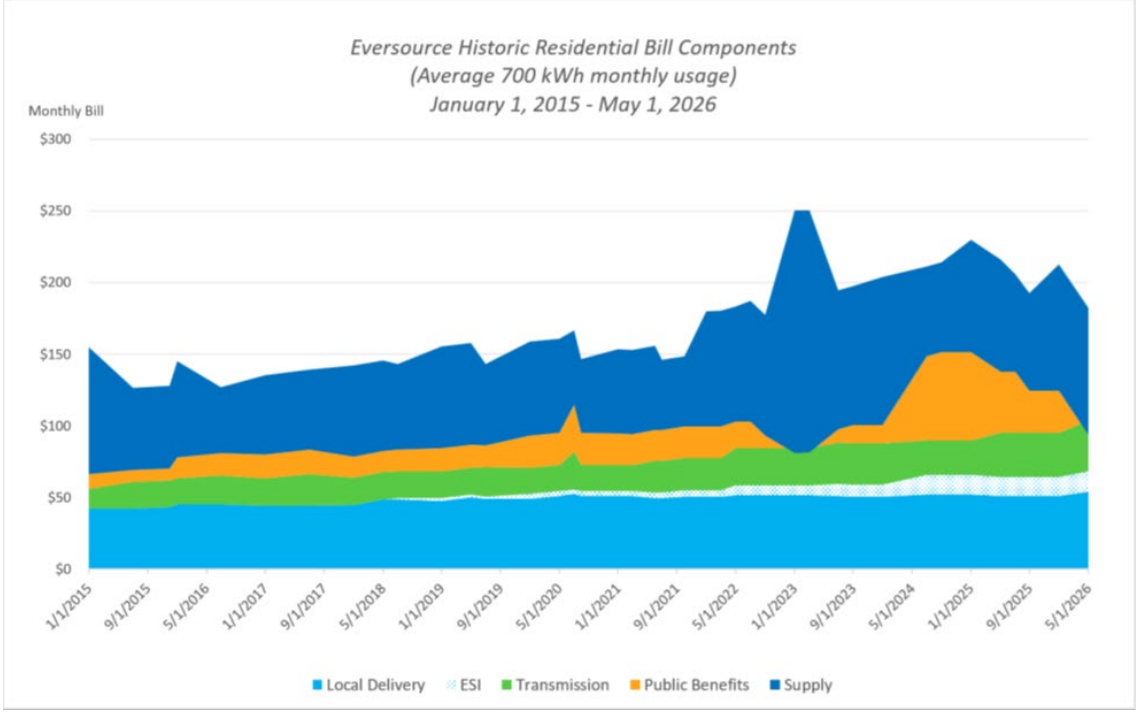
currently missing. The question is whether the distribution system is being invested in at the right level and the right pace — neither over-spending nor under-spending. Overspending (often referenced as "gold-plating") would be investment that channels customer dollars into plant additions that do not necessarily deliver commensurate value. Conversely, under-spending degrades reliability and, over the long run, creates more costs for customers. The Investment Calibration Framework developed in Sections III and IV are the operational expression of "Balance" affordability.

We present this lens because its execution is core and central to regulatory ratemaking. We have grown increasingly concerned that the very real affordability issues, as well as the public call to decrease utility profits as a salve for the pain point that customers are feeling, will lead to decisions that will reduce core elements of running a distribution network effectively and reliably. There is a body of documented experience, which we review in Section III, showing what happens to customers when investment is allowed to fall below the calibrated range. We offer those cases as cautionary evidence. Our aim is to give PURA a perspective as to the underinvestment "tail" before it materializes, not to assert that any particular outcome is preordained here.

Q. Where does this examination of distribution rates fit into the context of the customer's total bill components?

A. The volatility customers have felt in recent years sits almost entirely outside the distribution charge. Eversource has presented the following illustration of the customer's total bill components in Exhibit CLP-ELP-1, which we duplicate here:

Figure 2: Customer Bill Components, 2015 to 2026



Since September 2021, the representative bill has experienced volatility in supply (in dark blue above) and public-benefit costs (in orange above), as well as a larger percentage of the customer bill apportioned to the supply and public benefits components. Thus, it is clear that the changes

that are drawing public attention were caused by other items on the bill, not a distribution event. That history also explains the shape of the Company's request. The plan before PURA is a targeted plan directed at the condition of the existing system. The targeted system performance ("TSP") plan, rather than a broad expansion program, and its distribution bill impact, should be evaluated against the volatility customers have actually experienced.

Simplified, the bill components shown in Figure 4 in Section III.E of our testimony show an even starker differentiation of the distribution component of the customer bill when isolated and adjusted for inflation.

Consequently, viewed over the longer term, the distribution charge has grown modestly in real terms and roughly in line with general inflation. Expressed in constant January 2026 dollars, the local delivery charge rose approximately 9 percent between 2015 and 2026 — or, on the order of 0.8 percent per year — and has been essentially flat since the Company's last distribution rate case (2018), rising about 0.2 percent between 2019 and 2026 in real terms.

Q. Have you examined ‘‘Budget’’ affordability as set forth in RE08 and does the targeted system performance plan ‘‘pass’’ the 17-12-03RE08 Affordability Test?

A. Yes. As shown and described in detail on Exhibit IAP-7, “RE08 Affordability Evaluation of Reliability Related Capital Investment," the Company’s reliability investments meet the affordability test in RE08. Using data, definitions and benefit-cost analysis provided by the Company, we have determined that the program budget meets PURA’s affordability standard because the program budget does not exceed the Company’s historic average annual reliability program budget, using a data set of the annual reliability program budgets from the 10 years preceding the test year and factoring in reasonable escalation factors. We escalated historic capital expenditures using the Handy-Whitman index because it reflects escalation of utility costs over time and has an index specific to utilities in the Northeast. In addition to the affordability test, Exhibit IAP-7 shows that the investment levels the Company is proposing in its 5-Year TSP are effective and efficient, in that the investment levels, respectively, reduce SAIDI and have a greater than 1 benefit-to-cost ratio.

Q. Does the RE08 test stand as the correct definition of affordability?

A. No. Although the TSP does pass the RE08 test, as we understand it from PURA’s decision in RE08, we do not view that this method as a sound

definition for affordability. As written, the test accounts for "reasonable escalation factors" but determining those is a difficult exercise, accounting for multiple drivers, like inflation, aging infrastructure, exogenous grid stressors like weather events and electrification and standardized equipment sizes. Additionally, as discussed further in the Balance section of this testimony, baseline reliability that is escalated only by inflation does not take into account spending necessary to maintain and/or improve reliability over time from a practical, "on-the-ground" perspective."

Q. What about ''Burden'' affordability?

A. This element refers to customer affordability. The Company has put significant time and effort into establishing and improving the multi-tier low-income discount rate originally discussed in Docket No. 17-12-03RE11 and continues to examine the tiers in this rate proceeding in order to support low-income customers and balance the costs of the discount with overall affordability for all customers. For this discussion, we refer you to the Customer Service & Affordability testimony of Company Witnesses Jess Cain, Jared A. Lawrence, and Andrew C. Belden (Exhibit CLP-Customer-1).

Q. Please summarize the principal conclusions of your testimony in this section.

A. Our principal conclusion is that CL&P's proposed capital plan is affordable, from both the customer's and the regulator's perspective, and that it should be evaluated as a question of investment *calibration* rather than investment *compression*. Our specific conclusions are as follows.

All three definitions of affordability related to the three "Bs" – Budget (the Company's perspective), Burden (the customer's perspective), and Balance (the regulator's perspective) – must be achieved in this case, focusing on Balance.

Affordability is best understood as a calibration of investment at the level and pace that delivers customer value at a reasonable cost. The objective is not to minimize spending or to starve the system of infrastructure capital. Instead, it is to invest at the level and pace that delivers reliability and value to customers efficiently. Calibration is measured against the reliability and performance the investment is meant to produce. Thus, the right question is not "how little can be spent" but should be "is each dollar of investment buying a commensurate reliability or service benefit." The goal is reasonable recovery, in which structured ratemaking mechanisms govern the pace at which prudent costs reach customers and hold the Company accountable over time. A ratemaking mechanism

does not itself determine whether an investment is effective or efficient; that is tested through planning, benefit-cost analysis, and prudence review. But the mechanism's design shapes the financial environment in which those investment decisions are made. An overly generous mechanism imposes no discipline, an overly tight one shuts out necessary work, and a balanced mechanism gives the Company both the resources and the incentive to allocate each dollar where it is most effective.

Another lens for calibration concerns investor profits and perceived concerns about gold-plating. In reality, utility investors can earn returns at *both* tails of the investment distribution — through over-investment (viewed as "gold-plating) and, paradoxically, through sustained underinvestment, where deferred costs and reduced operating expense can inflate near-term financial performance even as the system degrades. Because returns can be earned at either extreme, attempting to engineer affordability by compressing the authorized return on equity or capital recovery is an unreliable instrument; it does not reliably move the Company toward the calibrated center. Thus, the first principle should instead be the delivery of capital investment that is both efficient and effective.

The affordability inquiry should also focus on utility efficiency and related standards. That means scrutiny of capital category and project-level prudence and the application of system performance standards. These are the tools that actually hold distribution investment within the calibrated range, together with metrics that measure whether spending is controlling cost and delivering value.

III. THE INVESTMENT CALIBRATION FRAMEWORK

A. Overview

Q. What is the regulatory compact and why does it matter to an affordability analysis?

A. By itself, the term "regulatory compact" is sometimes overused, particularly by utilities struggling with regulatory decisions that are different from expectations. However, the concept *underlying* the term remains sound, i.e., the foundational bargain that utilities and state jurisdictions have entered into is an exchange of value where (1) the utility receives an exclusive service franchise; accepts a continuing obligation to serve all customers within its franchise territory; and builds, maintains, and operates a safe and reliable system to the benefit of customers; and (2) the utility is eligible to recover the cost of meeting those obligations, including a fair return, once deemed reasonable and prudently incurred in furtherance of those obligations by the regulator.

The issue is that affordability is not a separate objective layered on top of that bargain. Instead, it is an inherent feature of that exchange. The exchange permits recovery only of costs that are "prudent," and only to the extent the result is just and reasonable. That standard is itself the "affordability" discipline, or the mechanism by which the bargain constrains investment to the level that delivers value to customers. When the compact functions – there is clear, transparent reporting, sound metrics, and spending calibrated to that value, and customers are then receiving reliable service at a reasonable cost. Prudence, as traditionally applied, however, asks whether a decision was reasonable when it was made. The investment affordability inquiry we describe asks further questions of a reliability investment, which is whether it is effective, whether it delivers the reliability or service benefit it was meant to buy; whether it is efficient; whether it delivers that benefit at an appropriate cost relative to the alternatives. An investment may be prudent, and even effective, without being highly efficient. The Company's showing in this case is directed at all these considerations, and we use these terms in those distinct senses throughout this testimony.

Notably, the compact can fail in two directions – and customers pay in both instances. The compact can fail toward over-recovery when spending exceeds what is needed or prudent; customers pay for that

immediately, in higher bills. Conversely, the compact can fail toward under-recovery when prudent investment is deferred or denied in the name of near-term savings. Customers pay for that later, and typically at a multiple of the temporary savings the deferral appeared to produce, because deferred risk accumulates non-linearly and arrives years on as the next decade's cost. The regulator's role in the compact is to hold spending between those two failure modes, to verify that investment is calibrated to customer value, neither over-built nor under fed.

The case studies in Section III.C discuss the realization of the under-recovery tail, examples of a breakdown in the compact's verification function, and of what that failure costs customers. They are also why we treat underinvestment as the tail this record most needs to be wary of. The cost and risks of underinvestment can be invisible when the "savings" are booked and that risk materializes only years later. We offer them, and the framework that organizes them as a means of keeping the compact intact, of giving PURA a way to recognize and prevent these breakdowns before they compound into customers' bills and result in a degradation of service.

Q. Does performance-based regulation itself ensure that investment is appropriately calibrated?

A. No, not by itself. No ratemaking structure, performance-based or otherwise, determines whether a given investment is effective or efficient; that is the work of planning, engineering, and execution, tested through benefit-cost analysis (if applicable) and the *post hoc* prudence review. *What a ratemaking mechanism determines is the financial environment in which those investment decisions are made*, and performance-based ratemaking specifically can create investment frameworks to tie in measures of effective and efficient capital spending. As we conclude above, that environment must be balanced, neither so generous that it imposes no discipline nor so unyielding that it constrains necessary work. Performance-based regulation, properly designed, is that balanced mechanism, and it aligns accountability with each of the three Bs. Performance-based regulation conditions cost recovery on discipline by fixing spending allowances in advance — for capital, O&M, or both — and escalates them only in response to objective economic indicators such as inflation. Performance-based regulation also replaces repeated rate cases with a defined multi-year plan, so costs reach customers at a measured pace. It gives PURA a defined plan, schedule and defined commitments against which the Company's performance can be verified over the term. Performance-based regulation does not produce

calibration on its own, but it is the structure that makes calibration achievable and holds it in place, provided the Company performs, which is exactly the condition the mechanism exists to enforce.

Q. Would you please illustrate what you mean by the Investment Calibration Framework?

A. Yes. Please refer to Figure 3, below.

Figure 3: The Investment Calibration Framework[4]

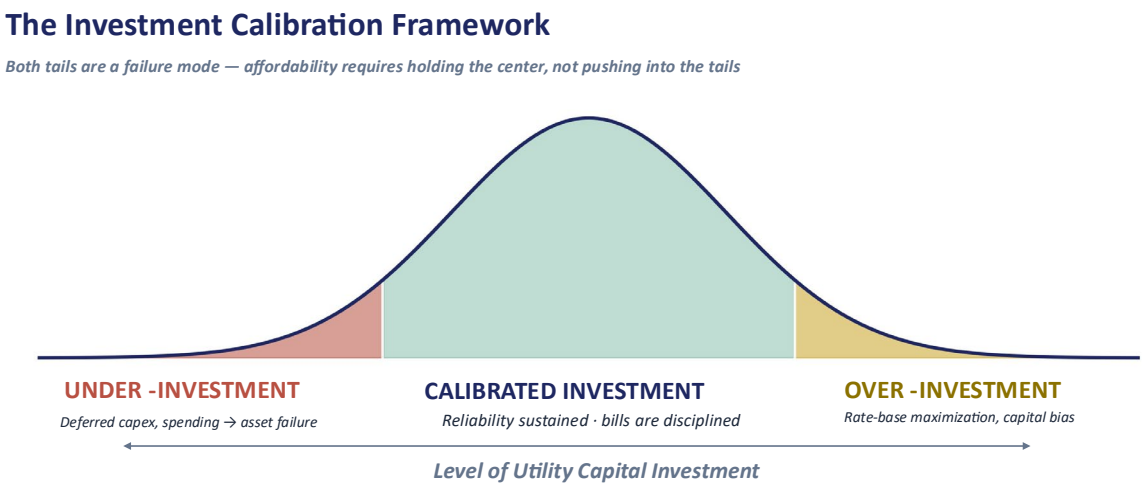


Figure 3, above, expresses Balance affordability as a question of degree rather than direction. The horizontal axis represents the level of utility capital investment, and customer value is greatest not at the extremes but across a calibrated middle range, where the distribution system is

[4] Source: Developed by Apex Analytics, 2026

funded well enough to sustain reliability while bills remain disciplined. The framework's central premise is that *both* tails are failure modes.

To the right lies overinvestment — the familiar concern with gold-plating and rate-base maximization, in which customer dollars are channeled into capital that increases investor returns without delivering commensurate value to the system. To the left lies underinvestment, in which deferred capital spending is experienced first as savings, but later as degraded reliability, accelerated asset failure, and, over time, a higher total cost to the customer than disciplined investment would have produced. Affordability, properly understood, is not the leftward push toward minimum investment; it is the discipline of holding the center.

The asymmetry is what makes the left tail the more dangerous one; the costs of overinvestment are visible and largely linear and are checked through the ordinary regulatory review process, whereas the costs of underinvestment accumulate quietly and non-linearly, surfacing as failures that are far more expensive to remedy than they would have been to prevent. The analytical apparatus we develop in Sections III and IV are designed to locate where on this curve a given investment program sits, and to give PURA a means of recognizing the underinvestment tail before it materializes.

Q. What is the relationship between utility investment and customer affordability over time?

A. The relationship between utility investment and customer affordability is an optimization across time, not a cost-control exercise within a single period. A simple analogy makes the point: if a homeowner defers repairs to a leaking roof to save money this year, the damage compounds, and the eventual cost of a roof replacement is far more than the maintenance avoided. Thus, the regulator's responsibility is not only to control costs in the current period, but also to optimize investment across the full horizon over which the assets deliver service and to minimize risk and exposure from underinvestment. In addition, the Company's customer team will confirm that customer preferences are that, if rate increases have to come, their experience is improved where rate increases are more gradual. Although the concept of "gradualism" in utility ratemaking is traditionally associated with the avoidance of "rate shock," it is also an affordability concept in the context of a socioeconomic environment where the customer is experiencing cost changes across the range of their household expenses all at the same time. The Investment Calibration Framework that we describe is a way of operationalizing that responsibility.

B. The Two Tails Are Not Symmetric

Q. Is over-investment the risk PURA should be most concerned about?

A. Over-investment is a real risk in some circumstances and PURA is obligated to guard against it. It is the capital bias concern identified in the regulatory-economics literature and summarized in the LBNL May 2026 study. The proposition is that, where a utility's authorized return exceeds its actual cost of equity, the utility can be incented to favor capital solutions over lower-cost non-capital alternatives. We do not dismiss this concern and we want to be clear that we are not asking PURA to dismiss this concern.

However, there is a growing tendency to treat potential over-investment as the *only* failure mode worth policing, and in our view, that is a mistake. Even over-invested capital is typically effective in the narrow sense that it does produce a working asset, albeit one of a lower marginal value for the customer. Where it fails is efficiency. Whereas under-investment fails on both dimensions at once – it produces *no* asset in the face of a real system need; and it provides *no* benefit or value for the dollar. Between an inefficient asset and an unmet need, the unmet need is the more dangerous outcome for customers over time.

Moreover, the under-investment tail behaves very differently from the over-investment tail. In the near term, it does not look like a problem at all – instead, it looks like cost discipline. This is an affordability paradox, i.e., reduced near-term spending produces a lower revenue requirement and politically visible bill relief; but the system's creeping failure does not look like failure at the outset. Instead, it looks like savings. The failure shows up only over time, and when it does, it is sudden and not incremental.

C. The Asymmetric Allure of Underinvestment

Q. Why is the underinvestment tail particularly dangerous?

A. Beyond the structural asymmetry we describe in Section III.A, two features make this tail especially problematic – and its allure is unusually broad. Three different actors are drawn toward it at the same time. A utility may be tempted to defer prudent investment to improve near-term financial results, a regulator may be under pressure to demonstrate visible "affordability" action, and intervenors may find it natural to frame the affordability problem as one of excess utility returns. The tail is dangerous, in part, because so many incentives point toward it at once, and few point the other way.

The customer cost arrives late and exceeds the savings it preceded. Deferred asset-condition work does not announce itself; it surfaces later as more expensive storm and emergency restoration, as casualty exposure from a weaker system, and — in the most serious documented cases — as after-the-fact cost recovery and repriced capital that raise distribution rates for years. The cases we examine in Section III.D, including PG&E and the MBTA, trace exactly that progression. We present them as a documented record of how the pattern has unfolded elsewhere, not as a prediction. The recurring lesson is simply that the value of delay rarely exceeds the value of timely action.

In the next section, we will highlight national cases involving extreme events, where tail risks appear often. Connecticut and the Northeast are not insulated from exposure to major weather events. CL&P's service territory has experienced repeated severe-weather stress — the catastrophic storms, specifically Isaias in 2020, as well as other major storm events are evidence of that exposure. The age and condition of distribution assets is a significant determinant of how a system performs when that stress arrives. We do not predict any particular outcome for CL&P, and we draw no causal inference from the cases discussed below. The point is narrower – asset condition and extreme-event exposure interact, and that interaction, is why the calibration of system reliability

and infrastructure investment is a critical decision made before events occur rather than after the fact.

D. Case-Study Evidence — The Underinvestment Tail Materialized

Q. Are there documented cases in which the underinvestment tail actually materialized, and what do they show?

A. Yes. We present four documented instances in which the regulatory compact broke down on the under-investment side, and one affirmative example in which calibrated investment worked. Read together, these cases make a single point – that is, spending on the system, calibrated to need, protects customers, while deferring that spending harms the system and ultimately costs customers more. The throughline is economic balance.

Q. What does the Pacific Gas & Electric (''PG&E'') experience show?

A. PG&E is an anchor case, and it shows two things. First, it shows the danger of deferral. A multi-decade pattern of deferred inspection and maintenance, documented not as an isolated lapse but as a pattern by three independent institutions, culminated in the November 8, 2018 Camp Fire, when a worn component on a transmission tower built in 1921 failed, killing 85 people and destroying the town of Paradise. The California Public Utilities Commission's Safety and Enforcement Division found the shortcomings on the failed line "were not isolated, but rather

indicative of an overall pattern of inadequate inspection and maintenance" of PG&E's transmission facilities.[5] PG&E pled guilty to 84 counts of involuntary manslaughter,[6] and the federal judge supervising its probation found that "for decades it neglected its duties" concerning vegetation and hazard-tree management.[7] PG&E entered Chapter 11 on January 29, 2019.

Second, the PG&E situation shows what a bankruptcy does to customers, because the failure did not resolve the cost for ratepayers; instead, it began a long tail of costs. Following emergence from bankruptcy, the 2023 general rate case raised typical residential bills approximately 12.8 percent in 2024, on the order of $32.50 per month, with the company projecting total increases near $50 per month.[8] Customers of the three California utilities fund roughly half of the approximately $21 billion AB 1054 wildfire fund through a 15-year nonbypassable surcharge.[9] Wildfire-related work is now accounting for approximately 18 percent of system costs. Bankruptcy, in other words, is not a customer remedy; it is a customer cost that arrives after the apparent savings have long since

5 CPUC SED, Camp Fire Incident Investigation Report, Nov. 2019, OII I.19-06-015

6 Butte County Superior Court, 2020

7 Final Comments on Probation, U.S. v. PG&E, N.D. Cal. Cr. No. 14-0175, Jan. 2022

8 CPUC Decision D.23-11-069, Nov. 16, 2023

9 AB 1054, Cal. 2019

been spent. This example argues that – deferral is not a saving, it is a loan from the future at one of the worst interest rates in the industry, and leads to the situation where hedge funds are now the decision-makers in utility boardrooms.

Q. What does the Hawaii Electric example add that the PG&E experience does not?

A. Hawaii Electric carries a distinct claim, which is that a utility's balance-sheet capacity is itself a customer-protection asset, and a utility whose financial capacity is thin relative to its catastrophic exposure cannot absorb the tail event when it arrives. The August 8, 2023, Lahaina fire, found by the joint Maui Fire Department/ATF investigation to be accidental and utility-associated, originating from re-energized broken lines igniting unmaintained vegetation,[10] killed 102 people. The liability exceeded the enterprise's entire pre-fire market capitalization. Within roughly ten days, the company was downgraded from investment grade to deep junk by both major credit-rating agencies; the dividend was suspended; and the company ultimately issued approximately $558 million in dilutive equity, sold its bank subsidiary, and reported a $1.4 billion net loss with a $1.875 billion wildfire liability accrual.[11] Hawaii

[10] MFD/ATF Origin and Cause Report, Oct. 2, 2024

[11] HEI FY2024 Form 8-K, SEC EDGAR CIK 0000354707

Electric avoided bankruptcy only through settlement. The State of Hawaii then enacted a financial scaffold, a liability cap, a securitization authority of up to $500 million, and a wildfire recovery-fund study, to restore the company's access to capital.[12]

This was also a deferral story. The company spent under $250,000 on wildfire projects in the years before Lahaina and described its own ignition risk as "significant" in a 2022 filing.[13] The story is the balance-sheet: debt capacity is the emergency reserve, and a utility cannot break that glass twice. Where PG&E shows the aftermath of operational deferral, HECO shows the structural inability to absorb a shock. Our point only is that the underspending tail risk is one that customers ultimately bear, with potentially a seismic difference in cost for the customer.

Q. What's the story with the Massachusetts Bay Transportation Authority (''MBTA'') in Boston?

A. The example of the MBTA is valid for this discussion. The MBTA is a non-profit public authority, not motivated by profit, that had its capital structure adjusted to the detriment of customers. A 2007 Massachusetts Transportation Finance Commission report found that about 35 percent of the MBTA's outstanding debt — roughly $1.8 billion — was attributable

[12] Act 258 / SB 897, 2025

[13] Docket No. 2022-0135

to Central Artery/Tunnel (aka the Big Dig) commitments and was "rightly the responsibility of the Commonwealth, not the MBTA."[14] That debt was never reallocated and what happened next is still being untangled. The carrying cost crowded out maintenance for two decades, the state-of-good-repair backlog grew into the tens of billions, and the degradation became a safety failure. The Federal Transit Administration's Safety Management Inspection, only the second in the agency's history, found a "substantial risk of death or injury," following a rider's death caused by equipment that should have been retired years earlier.[15] Today the only levers left, fares, service or securitization, eroded the ridership that funds the system. This is the "affordability" death spiral in its purest form, and one that the Chairperson of the Massachusetts Department of Public Utilities has a front seat on, experiencing the harm as a capital-intensive public transportation entity fell behind in its ability to keep up with capital repairs, as well as general operation, maintenance and training.

Q. What does Entergy New Orleans show, and how does it bridge to your recommendations?

A. Entergy New Orleans is an example of the full under-investment sequence, budget reductions, followed by degraded performance, followed by a

[14] Transportation Finance in Massachusetts: An Unsustainable System, March 2007

[15] FTA Safety Management Inspection, Final Report, Aug. 2022

regulatory finding connecting the two, and of what it costs to build a calibration apparatus after the fact rather than before.

The disinvestment came first, and it was quantified. The record developed in the Council's investigation showed multi-million-dollar reductions to distribution maintenance and capital preceding the reliability decline, including an approximately $21 million reduction in distribution capital additions from 2014 to 2015 and the removal of $1 million from a line-repair fund in 2013. The performance consequence followed. The company's own report to the New Orleans City Council (Entergy New Orleans' regulator) disclosed 2,599 distribution outages over the twelve months ending May 31, 2017, of which 1,462 — 56 percent — occurred in fair weather, and a 2018 assessment by the company's own contractor, Quanta Technology, found that average outage minutes per customer nearly doubled between 2013 and 2017. These were not storm outages. They were the operating signature of a system being maintained below its need. The Council opened its investigation in 2017,[16] and found the company "did not act prudently," and imposed a $1 million penalty.[17]

[16] Resolution R-17-427, Docket UD-17-04

[17] We note the penalty itself was litigated, a court initially set it aside because the Council had not yet adopted reliability standards, and the Council re-imposed it after adopting them,

Then, the Council built a calibration apparatus piece by piece, as enforcement: minimum reliability standards (SAIFI 1.53; SAIDI 178.2 minutes, with annual penalties up to approximately $3.7 million), mandated reporting, and budget review. When performance deteriorated again in 2024–2025 — equipment-caused interruptions roughly doubling in two years, by the company's own data, that mandated reporting is what detected it, and the Council has now ordered an examination that treats budget adequacy and reliability as a single question.[18] We note, in fairness, that the company attributes part of the 2025 deterioration to a sharp increase in lightning activity, and we do not rest the point on the single-year total.

New Orleans got calibration retrofitted through eight years of litigation, at cost to both customers and the company. This testimony offers PURA the same apparatus voluntarily and in advance presented by CL&P with defined metrics, transparent reporting, and the Company's reliability benefit-cost model placed on the record (see Sections V and VI).

but the underlying factual findings connecting disinvestment to deteriorating reliability are what matter for my purpose here.

[18] Resolution R-25-626, Dec. 18, 2025

Q. Is there a single juxtaposition that captures the stakes?

A. There is, and I present it as parallel documented facts rather than as proof of causation. During Hurricane Ida in 2021, all eight transmission lines into New Orleans failed simultaneously, a 1960s-era tower fell into the Mississippi River, and the blackout contributed to at least eleven heat-related deaths.[19] Thirteen months later, a stronger storm struck a hardened Florida system 300 hundred miles to the east, and not one transmission structure failed. The wind conditions on the two systems differed, and we do not assert that the New Orleans failures were caused by deferred maintenance. However, the two outcomes are presented side by side because they frame the choice before PURA.

Q. Where was ‘‘calibrated investment’’ successful — the affirmative case?

A. Florida Power & Light is the affirmative bookend, and it is the answer to the obvious objection that heavy investment is itself what is unaffordable. Over two decades, Florida’s most aggressive hardening program was run through a genuine calibration apparatus, statutory ten-year storm-protection plans, three-year refreshes, and an annual cost-recovery clause with prudence review,[20] including an Office of Public Counsel that proactively guarded against the over-investment tail, cutting roughly $3.4

[19] Entergy New Orleans storm filings, Docket UD-17-04

[20] Fla. Stat. § 366.96 (2019); Fla. Admin. Code R. 25-6.030, 25-6.031

billion from the lateral-hardening program when the cost-benefit case thinned.[21] The performance, documented in part by the regulator itself,[22] moved from roughly 100 transmission structures lost and a 5.4-day average restoration in Wilma (2005) to zero transmission structures lost and restoration measured in fractions of a day in the most recent storms. This result could be viewed as indicative of "over investment" into the system, but during that period, the residential typical bill fell approximately 20 percent in real terms and remains below the national average. There are lots of exogenous and regional factors driving these two factors that are not replicable in Connecticut, but the purpose of my proposal around a calibrated investment is that it is not the enemy of affordability; over the long term, it is the heart of affordability.

E. National Affordability Benchmarking — CL&P Relative to Peer Utilities

Q. Before turning to CL&P specifically, what is driving increases in distribution rates across the industry, and is Eversource's pattern in that regard, unusual?

A. A big driver in cost increases across the country is simply that the equipment costs more, and that is not something any utility controls. The same study tracks producer prices for the basic hardware of a distribution

[21] FPSC Order PSC-2022-0389-FOF-EI, Nov. 10, 2022, Docket 20220051-EI

[22] FPSC, Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions, July 2018.

system, and those prices have risen far faster than general inflation. Measured from 2004, wire and cable is up roughly 411 percent; transformers about 265 percent; switchgear about 140 percent; and wood poles about 123 percent — against general inflation of about 71 percent. Much of the recent jump traces to post-pandemic supply-chain pressure. The plain point for PURA is that a real share of the increase is just the price of poles, wire, and transformers climbing faster than the rest of the economy — something CL&P shares with every utility in the country and did nothing to cause.[23]

The data also show a shift in what utilities are spending on. Across a sample of 22 utilities, 20 utilities plan to spend more on maintaining and strengthening the system they already have — replacing aging equipment, improving safety and reliability, and hardening against storms — rather than on building it out for new load. Spending on the existing system, not expansion, is what most utilities are doing, and Eversource is one of them. The study references Eversource's "Reliability" budget the same way the Company does — as a mix of

[23] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 19.

hardening, asset replacement and reliability upgrades,[24] validating the Company's approach.[25]

A utility in the calibrated range should be spending mostly on the system it already has; a utility that is under-investing will be putting that work off; and a utility that is gold-plating will be over-building for load that is not there or not expected. The fact that 20 out of 22 utilities are spending mainly on the existing system tells PURA that CL&P's pattern is not unusual. Why CL&P's specific investments are needed is covered in the Company's testimony, Exhibits CLP-TSP-1, CLP-TSP-2 and CLP-TSP-3. Our narrower point is that the shape of CL&P's spending looks like the rest of the industry's, not like an outlier.[26]

Q. How does CL&P's own distribution growth compare to that national pace?

A. Nationally, distribution costs have been the fast-moving piece of the bill — growing about six percent a year above inflation and driving roughly

[24] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory.

[25] Our analysis in this testimony excludes storm costs that are the subject of the Company's separate securitization proceeding (Docket No. 25-12-13). That treatment is deliberate, and securitization is itself an affordability measure, i.e., it removes catastrophic-storm costs from base rates and finances them at lower cost over a longer period, an approach LBNL identifies among regulators' most effective near-term tools, with documented savings in the hundreds of millions where applied. [Exhibit: IAP-4, pg. 64.] Storm-related amounts that remain in base rates are included in my analysis.

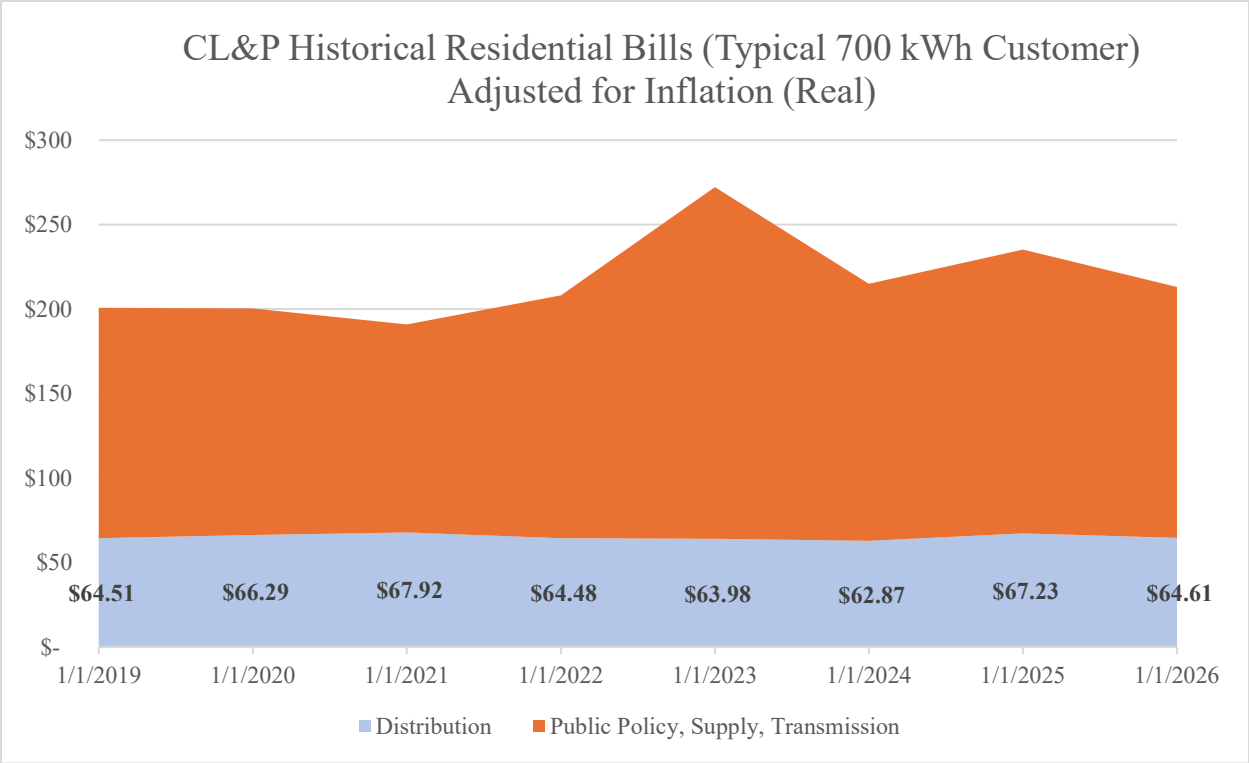
[26] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, at p. 30.

30 percent of the rise in retail rates. CL&P's distribution costs have not grown anywhere near that fast. The distribution part of a CL&P customer's bill has grown only modestly, and far more slowly than the national average.

Over roughly the last decade — from January 2015 through 2026 — the distribution portion of a typical residential bill (local delivery plus the ESI capital tracker) grew from about $42.53 to about $65.66 a month. After adjusting for inflation, that is a real increase of about $5.42 (9 percent), or on the order of $0.45 or 0.8 percent a year. And since the Company's last distribution rate case in 2018, it has been close to flat in real terms as shown in Figure 4, while allowing the recovery of the costs associated with $2.7 billion of invested capital for infrastructure upgrades. Set that against the national distribution-cost growth of roughly six percent a year above inflation, and the contrast is clear -- while distribution was the main driver of rising bills across the country, at CL&P it grew slowly and roughly kept pace with the broader economy.[27]

[27] Source: Company provided data for historic rates, adjusted for inflation.

Figure 4: Historical Bill Components, adjusted for Inflation



This leads us to the request in this case. The Company describes the infrastructure needs of the system in Exhibits CLP-TSP-1, CLP-TSP-2 and CLP-TSP-3 and shows that, when examining why bills have increased, distribution was not what drove CL&P's bills up historically, and the bill history in Section II (including Figure 2) shows it was non-distribution supply and public-policy charges that moved, not distribution. Accordingly, CL&P is spending under the historical average and it has been spending modestly, not aggressively.

IV. APPLICATION TO CL&P'S PROPOSED CAPITAL INVESTMENT

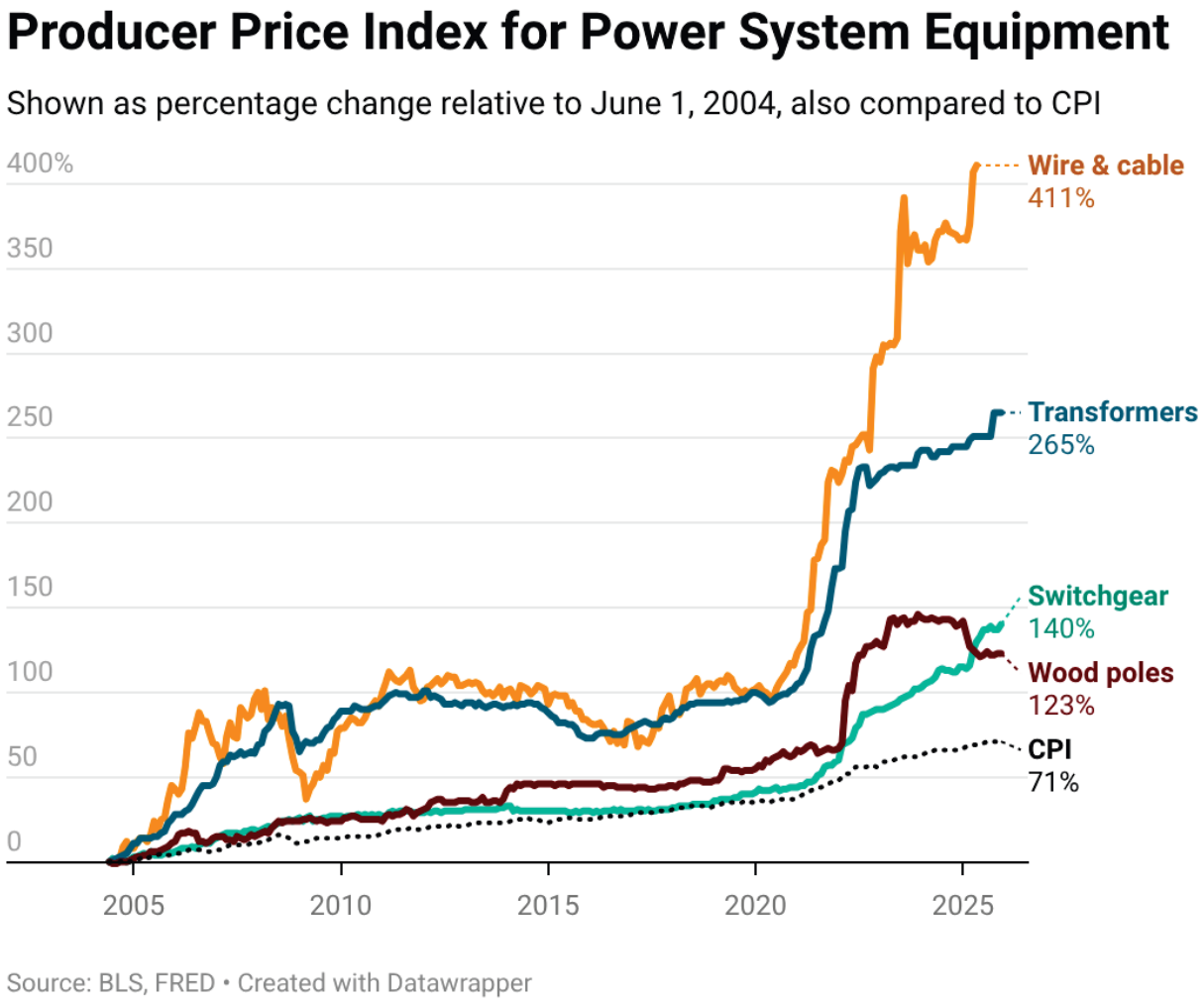
Q. What is driving distribution rate growth across the industry?

A. IAP-Exhibit-4 finds distribution spending rising about 6 percent per year nationally since 2014, roughly four times the prior two decades, consisting mostly of capital, with depreciation and interest on that capital the single largest driver of the resulting rate impact. Distribution-cost growth accounts for about 30 percent of the national increase in retail rates. Much of the recent capital-cost growth is external to any utility discretion: post-pandemic supply-chain pressure and equipment-price inflation far above the consumer price index ("CPI") — per the study producer-price data, wire and cable, transformers, switchgear, and wood poles all rose well above the ~71 percent CPI increase since 2004.[28] Notably, LBNL reports that, in real dollars, average Investor Owned Utility retail rates actually *declined* by about half a cent per kilowatt-hour over 2014–2024. Thus, rising distribution costs did not drive real rates up; instead, they reduced the size of a real dollar decline. The affordability problem is real, but it is a problem of nominal bills meeting stagnant incomes, an inflationary environment, and broader increased prices across multiple sectors of the economy, not of overspending of

[28] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 19.

distribution rates.[29] The point for CL&P is that rising distribution cost is a national phenomenon with external drivers, not a Connecticut anomaly.

Figure 5: National Capital Cost Surge base on BLS Produce Price Index[30]



[29] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 17.

[30] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 19.

Q. Is New England an overspending region?

A. No, and the LBNL decomposition is the answer. ISO-NE shows among the highest distribution rate impacts in the country — and an intervenor will stop there and call it overspending — but LBNL attributes the New England pattern largely to a contracting sales base (the denominator), together with O&M, depreciation, and rising state taxes, rather than to high capital-expenditure growth. ISO-NE, in fact, had relatively slow growth in distribution expenditures even as its rate impact rose.

In other words, the high regional rate-impact number is a stagnant denominator-and-O&M story, not a capital-overspending story.

LBNL's May 2026 distribution-cost study found that over the past decade, the regions with the highest retail sales growth saw *declining* distribution rate impacts despite some of the fastest spending growth in the country, while regions with contracting sales (New England among them) saw rate impacts rise despite comparatively slow spending growth.[31] LBNL draws the corresponding prescription in its regulatory toolkit -- improving grid utilization by adding load spreads system costs across more sales and can reduce rates, particularly where growth is targeted to areas of the

[31] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 21-22.

grid with existing capacity.[32] Connecticut's distribution rate problem is, in meaningful part, a denominator problem — and the economic development rate is the instrument in this case designed to work on it.

Q. Where does CL&P place in relation to capital investment, specifically?

Q. The LBNL study finds that 20 of 22 sampled utilities plan more spending on managing the existing distribution system than on capacity expansion — so a reliability-weighted, low-capacity-expansion profile is mainstream-conservative, not anomalous — and the study planned-spending data place Eversource at the low end of capital growth among peers.[33]

Q. Where does CL&P fall against peer utilities on capital efficiency?

A. High — and the final benchmarking results confirm it on two independent methods. On unit cost, CL&P ranks 30th of 88 utilities, nationally, on capital cost per customer, and 6th of 22 among its Northeast peers. Its capital cost per customer averaged roughly 14 percent below the industry average over 2015–2024. The econometric analysis controls for labor prices, network density, and other business drivers, placing CL&P's

[32] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 69.

[33] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 19; LBNL also characterizes Eversource "Reliability" budget category as combining hardening, asset replacement, and safety-and-reliability — independent corroboration of the categorization the Company uses.

capital costs approximately 16 percent below the model-predicted benchmark. On total cost per customer, CL&P sits at approximately the national midpoint (46th of 88), in the first quartile of its Northeast peers (5th of 22), and about 5 percent below benchmark on both methods. That total-cost position is my framework rendered as data – CL&P sits within the calibrated range, not at either tail, with the below-average capital side marking the drift toward under-investment that this case corrects. It is an independent, CL&P-specific confirmation of the conclusion the LBNL national and regional data point toward. That is, CL&P has not been an above average capital spender.[34]

Q. CL&P's operations and maintenance costs have been characterized as comparatively high. How should PURA understand that?

A. As a reflection of circumstances and of policy more than of performance. Two factors explain most of CL&P's O&M position. Connecticut wage levels are among the highest in the nation, and distribution O&M is where labor lives — a workforce-intensive category for which any credible comparison must adjust.

Second, macro level data will pull public policy program costs in as O&M. Substantial program spending, energy efficiency and related public policy

[34] Exhibit CLP-PBR-3 Benchmarking Report

program costs, are booked to O&M accounts and flow through reported O&M even though they represent policy pass-throughs rather than operating decisions. For CL&P, Account 908 alone carried approximately $219 million in 2024. A comparison that does not strip those accounts out is measuring Connecticut's policy commitments, not the Company's operating efficiency. Indeed, the Company's own productivity consultant excluded these accounts from its industry study for precisely this reason, because they are driven by legislative and regulatory requirements rather than by the utility's efficiency in operating the distribution system. Its econometric model likewise confirms the labor point: labor price is the most marginal impact of O&M costs across the industry.[35] Lastly, the customer base must be taken into account. The less commercial and industrial load served by CL&P moving forward, the less over which to spread its costs, so per-customer measures run high for reasons unrelated to how the Company operates. This is a structural feature that the economic development rate discussed later in this testimony is designed to work on directly.

Both studies handle these policy-driven costs the same way. LBNL analyzes distribution infrastructure O&M separately from customer-

[35] Exhibit CLP-PBR-3 Benchmarking Report

assistance costs (Account 908), cautioning that utilities may allocate the latter to distribution service.[36] The Company's productivity consultant excluded those accounts from its industry study outright.[37] A comparison of CL&P's O&M that merges the two categories is measuring Connecticut's policy commitments alongside its maintenance work, a distinction both studies were careful to preserve.

An aging system that has been capital-constrained requires more maintenance, and older equipment takes more work to keep in service, so elevated O&M alongside modest capital spending is the operating signature of the underinvestment pattern described in Section III. And cross-utility O&M comparisons are unreliable without adjustment in any event, because utilities draw the line between capital and O&M differently. The Company's proposal to discipline controllable O&M going forward, an O&M-focused performance mechanism that shares realized efficiencies with customers, is addressed in the Consumer Dividend discussion at Section VI.E.

[36] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 13, 24.

[37] Exhibit CLP-PBR-2 TFP Report

Q. During the reporting for PBR, should peer benchmarking continue to be used or are there better measurement standards?

A. Once a multi-year rate plan is established, measuring the Company against itself, over time, can demonstrate controllable operating cost per customer against an inflation-based benchmark, capital spending against the approved plan, and reliability results against the plan's commitments. PBR will have regular public reporting, so PURA, stakeholders and the public see a trajectory rather than a single contested snapshot. Once a multi-year plan is established, peer comparisons are informative but require detailed studies since the comparisons depend on accounting alignment, wage and geography differences, and denominator choices, and each of those choices can be litigated, which can slow progress and tracking – and PBR should have direct annual feedback to the utility to drive efficiencies. The core question is how, using the Company's own accounting, its own territory, and its own customer base, is performance against reporting data.

V. AFFIRMATIVE RECOMMENDATIONS

A. Overview

Q. Much of your testimony has been about how PURA should *evaluate* affordability. Is the Company proposing anything affirmative *for* affordability?

A. Yes. The Company is bringing forward four mechanisms I would describe as real affordability measures — not framing, but concrete value to

customers. These include (1) a performance-based multi-year rate plan; (2) an economic development rate; (3) an optional residential space heating rate; and (4) a consumer dividend. Each has its own section or panel, and we do not describe them in depth here. Rather, our purpose is to explain why each is an affordability tool and how it fits the framework.

There is a simple logic connecting them. Two of the four work on the cost base itself — performance-based regulation disciplines the pace costs reach customers and creates the financial environment in which the Company is rewarded for spending efficiently (the numerator), while the economic development rate grows the load over which the system's fixed costs are spread (the denominator). The other two deliver value to customers directly: the optional residential space heating rate lowers the cost of electric heating for the customers who convert, while maintaining a cost basis of the rate design, so that Connecticut's electrification policy arrives as a discount rather than a burden, and the consumer dividend returns a share of realized efficiencies to every customer when the Company delivers them. Together they are calibrated investment made operational: discipline the numerator, grow the denominator, and give customers, those electrifying and everyone else, a share of the value.

B. Performance-Based Multi-Year Rate Plan

Q. Regarding a performance-based multi-year rate plan. Why is it an affordability tool?

A. A performance-based rate plans is an affordability tool because it changes the *pace* at which costs reach customers, and because it conditions recovery on discipline.

Consider the circumstances of this case. Under the traditional approach, a utility is able to stay out of a general distribution rate proceeding for several years, with a growing gap relentlessly building between its costs and its rates, and eventually it closes that gap with one large request for a change in base rates — driving the need for PURA to make a decision on a very significant rate increase all at once. A big, infrequent ask is hard on customers precisely because it lands all at once.

A performance-based ratemaking framework is full bodied, meaning that it is multi-year revenue setting combined with defined performance metrics and, where appropriate, performance incentive mechanisms, so that recovery and accountability travel together. It lets the Company recover costs in smaller, steadier increments at a controlled pace, so needed investment arrives as a series of manageable steps instead of an occasional spike. The smoother path is the more affordable one for a household at a given time, even when the total is similar. This is also not

just gradualism. In Alberta, for example, average annual residential bill growth fell from roughly 15 percent per year under traditional cost-of-service regulation to 4 to 6 percent per year under two successive PBR terms, and Ontario's Hydro One recorded more than $315 million in productivity savings, exceeding forecast, in the first three years of its multi-year plan.[38]

CL&P has experienced this dynamic under its current multi-year rate plan, established in 2018. As discussed by the Eversource Leadership Panel, the Company's capital investment recovery mechanism permitted recovery of costs incurred annually to upgrade, replace and reinforce electric distribution infrastructure for the benefit of customers.[39] Through the multi-year rate plan, the ESI rate was gradually increased such that the bill impact for customers was limited to less than $2 per month each year, on average, over an 8-year period, 2018-2025, while allowing the recovery of the costs associated with $2.7 billion of invested capital for infrastructure upgrades. This gradual roll-in of invested capital benefitted customers because – without the ESI – customers would now

[38] Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory, p. 65.

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

be facing a rate increase to accommodate $3.3 billion of incremental net capital invested since the 2018 rate review, instead of the $600 million that remains to be incorporated into rates over and above what the ESI will address through December 31, 2026.

Performance-based ratemaking is not a blank check. In its proper form, it rests on a commitment that the Company will hold controllable cost growth at or below input-cost inflation — matching, and through the Consumer Dividend committing to beat, what the industry has at best managed over the past two decades — and it ties recovery to performance rather than awarding it automatically. As a result, savings come from financial discipline. This is the standard that PURA should consider, which is that capital expenditures are both efficient, by controlling cost impacts that arise without the expenditures, and effective, in that it delivers the reliability it was meant to buy. The Company's specific proposal, as discussed in the testimony of the Eversource Leadership Panel, is a capital allowance capped at the approved forecast and reconciled annually, but only downward, paired with an O&M-focused performance mechanism. This approach is consistent with the regulatory toolkit the LBNL study describes, which includes multi-year rate plans

that contain costs by reducing the frequency of rate cases, strengthened efficiency incentives, and targeted performance mechanisms.[40]

C. Economic Development Rate

Q. Does the Company propose to establish an Economic Development Rate?

A. Yes. The Company is proposing to establish an Economic Development Rate ("EDR") applicable to qualifying large commercial and industrial customers. The EDR is offered as a rider to the otherwise applicable general service rate and is implemented through a Company-customer contract authorized under the tariff.

Q. What is the purpose of the Economic Development Rate?

A. The purpose of the EDR is to support economic development and affordability within the Company's service territory by providing targeted, time-limited electric rate incentives to customers that create incremental load and associated economic activity. Specifically, the EDR is designed to:

- Attract new business investment to the service territory;
- Encourage expansion of existing customers; and

[40] Exhibit IAP-4, "Exhibit IAP-4, "Electric Utility Distribution Costs," May 2026, Lawrence Berkeley National Laboratory"; Exhibit CLP-PBR 1-3.

- Improve utilization of the electric system through incremental load growth.

In addition to these traditional economic development objectives, the Company is proposing the EDR as a rate design tool that supports system-wide affordability. While affordability discussions often focus on bill assistance programs or short-term rate mitigation measures, rate design can also play a meaningful role in addressing long-term affordability challenges.

A significant portion of the Company's costs are fixed and do not vary with short-term changes in consumption. When incremental electricity usage is priced above the marginal cost of serving that load, each additional unit of consumption contributes not only to its own incremental cost, but also to the recovery of fixed system costs. As a result, increased utilization of the system allows fixed costs to be spread across a larger sales base, thereby reducing the average cost per unit.

The Company's marginal cost of serving incremental distribution load is below the otherwise applicable demand charge. The difference between the marginal cost to serve load and the existing rates is the range over which incremental load can be priced above marginal cost while still contributing to fixed costs. Pricing incremental load anywhere above the

marginal-cost floor produces revenue that offsets costs otherwise borne by all other customers.

Consistent with prior findings in Connecticut, the primary objective of an economic development rate is to attract incremental load or expansion of existing customers while ensuring that revenues from participating customers exceed the incremental cost to serve, thereby placing downward pressure on rates for all customers.

The Company's proposal is designed to achieve this outcome and produce net benefits to all ratepayers.

Q. How does the Company ensure that the EDR benefits all customers?

A. The Company will ensure that each participating customer satisfies a hurdle rate test, such that:

- The net present value ("NPV") of revenues from the incremental load, inclusive of any EDR discount, exceeds the incremental cost to serve, including any required infrastructure investments.

To the extent the base discount level does not achieve this outcome, the Company may adjust the discount within defined limits through the contract to ensure that:

- A portion of the economic benefit from incremental load is retained by existing customers; and
- The overall program produces net positive system economics.
- Or decline to provide the EDR if none of these conditions are met

This approach is consistent with prior findings requiring that a substantial portion of the benefit from incremental load be allocated to non-participating customers, thereby ensuring that the program contributes to lowering rates.

Q. How does the EDR support affordability?

A. The EDR supports affordability in three ways:

1. Improved System Utilization – Incremental load may increase utilization of existing infrastructure.
2. Enhanced Fixed Cost Recovery – Revenues collected above marginal cost contribute to fixed cost recovery, lowering pressure on base rates.
3. Rate Suppression Effects – Expected impact of reducing rates by spreading fixed costs across a larger base of kilowatt-hours, benefiting customers.

Because each participating customer would pay a rate above the marginal cost of its incremental load, every additional kilowatt served under the EDR makes a positive contribution to the recovery of fixed costs that would otherwise be recovered from other customers.

Q. Is the Company considering a repayment requirement for customers that go on the EDR but don't generated the forecasted incremental load?

A. Yes, an important element of the EDR is financial protection for existing ratepayers. To that end, the Company is considering a repayment requirement in order to ensure that all customers benefit from the EDR and that the envisioned affordability and economic benefits actually materialize.

Q. In summary, how does the economic development rate serve affordability?

A. It works the denominator, while, importantly, ensuring that the numerator is not unduly shifted or increased to other customers. Every distribution rate is a fraction: the system's costs on top, and the sales those costs are spread across on the bottom.

Fixed costs are spread across all customers, so in general, anything that adds load spreads the same costs over a larger base and lowers the share each existing customer carries. Bringing new load onto the system is therefore one of the most direct affordability tools there is for the customers already on it, provided that it exceeds marginal costs.

Nearly all of the effort in a rate case goes into the numerator, scrutinizing, trimming, and disciplining costs, and that work matters. But the denominator is just as powerful as an affordability tool. An economic

development rate is designed to attract that new load (including other positive economic benefits such as jobs, tax revenue, and economic opportunities) on terms set such that the new load still pays its contribution to fixed costs, with guardrails so existing customers are protected rather than subsidizing it. Done correctly, it is a win on three sides: existing customers see downward pressure on their fixed-cost share, the state gains jobs and investment, and the system increases system utilization. In our view this is one of the best available pathway to growth-driven affordability — and it connects directly to the benchmarking in Section V, where regions with growing load saw their distribution rate impacts fall while regions with contracting load saw them rise. An economic development rate pushes Connecticut the right way on exactly that variable.

D. Optional Residential Space Heating Rate

Q. Does the Company propose to establish an Optional Residential Space Heating Rate?

A. Yes. The Company proposes to establish an Optional Residential Space Heating Rate (ORSHR) applicable to qualifying residential customers, including those installing heat pumps.

Q. What is the purpose of the ORSHR?

A. Amongst other things, the ORSHR is designed to facilitate the transition to heat pumps. The Company is seeking to help reduce potential barriers that may prevent the adoption of heat pumps. Specifically, the rate is designed to:

- Mitigate the increase on electric bills that residential customers would potentially see when transitioning their heating to efficient electric;
- Support the state's climate targets, by reducing emissions and addressing the affordability barrier;
- Provide incentive for customers to utilize installed heat pumps for heating;

Q. How is the ORSHR related to affordability?

A. The ORSHR will offer lower winter electric rates to customers that choose to adopt a heat pump. That has a direct impact on affordability and depending on what type of heating source and equipment is being displaced by the heat pump, overall heating costs for those customers adopting heat pump technology may be reduced. The rate reflects a seasonal discount but is still set above the marginal cost to serve those customers, the expected result is that there will be more incremental load to spread the Company's fixed costs over. This should have an overall

beneficial impact for ratepayers, similar to the Economic Development Rate.

Q. How does the Company ensure that the ORSHR does not harm remaining customers that have not yet been able to transition to heat pumps?

A. The Company has designed the rate to be priced above the marginal cost to serve those customers. This means that the rate will fully recover the costs associated with providing service to that customer, so there is not any cross-subsidization. Customers that have not yet been able to transition to heat pumps will actually benefit from this rate because new incremental load from heat pumps will contribute to other fixed cost requirements, defraying what existing customers would otherwise have to help contribute towards.

Q. To reiterate, how does the ORSHR increase affordability?

A. Directly, for the customers who electrify. Connecticut has asked its residents to move to electric heat pumps, and the economics of that conversion turn on the price of the electricity that replaces the previous fuel. The ORSHR lowers that price: it is a discount for customers who convert to electric heating, so that the households answering the state's policy call sees the benefit on its bill rather than bearing electrification as a burden. That is affordability in its most literal form — a lower or comparable cost of heating for the customers making the transition and

it removes a large obstacle to adoption, which is the fear that heating with electricity costs more than the fuel it replaces.

The rate is also built to be fair to everyone else. It is grounded in cost-causation principles, so the discount reflects the terms on which heating load can be served rather than a subsidy collected from other customers. Heat pump load is primarily a winter load on a system whose costliest moments come on hot summer afternoons; to the extent that usage falls away from the system's peak, it is load the existing system is well positioned to serve. This means that the additional load can potentially drive down costs for everyone else. The load-shape analysis that determines exactly how heat pump usage lines up against the system peak, and the allocation of the discount across the components of the bill, sit with the rate-design panel. When customers want to electrify, the rate structure should make that choice affordable, on terms that are fair to both the customers who convert and to those who do not.

E. Consumer Dividend, Structured as an S-Factor

1. Purpose and Summary

Q. What is the purpose of this portion of your testimony?

A. We introduce and explain the Consumer Dividend, which the Company proposes as the S-Factor in its performance-based multi-year rate plan. We describe what it is, the affordability problem it is designed to address,

how it works inside the plan, how it is sized and delivered, and the principal questions that we expect it to raise. Our testimony is limited to the design and rationale; the rate-mechanics and tariff language are sponsored by the Company's rate-design witness.

Q. Please summarize the Consumer Dividend in plain terms.

A. The Consumer Dividend is a sharing factor inside the rate-plan formula, so that when the Company runs efficiently on its base-rate operating costs, a defined slice of that performance is shared back to customers. It is a downward signal in customers' favor that is generally static; it can never become a charge.

Q. Why do you refer to it as an S-Factor?

A. The terminology is used in other jurisdictions to refer to a specific surcharge or adjustment. The Company's PBR consultant uses the same term in its filed study and testimony to refer to the Stretch Factor or S-Factor (also referred to as the customer dividend), which is the sharing term in I–X–S frameworks adopted in other jurisdictions. In the performance-based plan that adjusts rates each year by an inflation factor less a productivity factor, an S-Factor is an additional sharing term in that formula. PURA has indicated it will determine the structure of an S-Factor in the Company's rate proceeding, considering how it interrelates with

other revenue-adjustment mechanisms and with performance incentive mechanisms, and deferring quantification to the rate case. The Consumer Dividend is the Company's proposed S-Factor structure for sharing operating cost efficiency, offered concretely so PURA has a specific design to work from[41].

2. S-Factor Changes

Q. What does the S-Factor address?

A. There is a persistent disconnect in utility regulation. When a utility operating company reports consolidated earnings to investors while also seeking new funding or a rate increase, customers reasonably ask why both are happening at once. The usual regulatory tools for cost discipline are penalties, a stick for poor performance, and regulators are understandably reluctant to hand a company more money for meeting or exceeding their customer obligations. The result is a misalignment among what the company wants, what customers want, and what the regulator can reasonably approve.

Q. How does the proposed adjusted S-Factor change that dynamic?

A. The proposed adjusted S-Factor turns a year of good cost performance into a direct and visible customer benefit, rather than something that only

[41] Exhibit CLP-PBR-1, CLP-PBR-2

shows up as company earnings. In effect, it is a form of earnings-sharing that operates *below* the authorized return, where the Company shares efficiency with customers although it is earning under its allowed return. This mechanism reframes the relationship between good financial performance and the customer benefit, so that when the Company runs efficiently, there is good news for the customer.

3. *How the S-Factor Works*

Q. Where does the S-Factor fit in the PBMRP?

A. The PBMRP adjusts base-rate operating costs each year by inflation, less a productivity factor, less the S-Factor. In shorthand:

Annual adjustment = I – X – S
inflation – productivity – S-Factor (Consumer Dividend)

The Company's PBMRP applies this to O&M only. Capital is recovered through a separate capital funding mechanism, so the S-Factor is sized against the base-rate O&M (Core Operating Expense) revenue requirement, not the whole bill.

Q. How is the Consumer Dividend deducted?

A. It is deducted the same way as a standard S-Factor or consumer dividend factor. It is a discount taken before revenue is collected, lowering the annual adjustment rather than adding anything to the bill. The S-Factor

represents a change in revenue the Company needs to collect because it ran efficiently that is shared back with customers. It is not a surcharge and can never become one; it is floored at its set 0.30%. Because it is a pre-collection sharing of realized efficiency rather than a separately recovered cost, it requires no reserve and carries no interest.

Q. What causes the Consumer Dividend to move up or down?

A. A single, transparent annual test would trigger the factor, which is the Company's controllable, Core Operating Expense per customer, measured against an benchmark escalated by the plan's composite input-cost index. If Core Operating Expense per customer comes in below the benchmark — that is, if the Company held the costs it controls below inflation — the dividend ratchets up. If it comes in at or above the benchmark, the dividend eases down. It is the efficiency itself that is measured, not earnings.

Q. How is the benchmark (the number to beat) set?

A. The same way a typical S-Factor is set. It is set by a fixed formula established in the rate case as part of the overall PBR structure. Therefore, it is not litigated each year and needs no special study. The benchmark in the first plan year is the approved Core Operating Expense per customer. Each year after, that figure is escalated forward by the

plan's annual adjustment factor, the composite input-price index (a labor cost index and a non-labor price index, weighted to the industry's O&M cost shares) net of the productivity factor, and divided by the number of customers. The Company's actual Core Operating Expense per customer is then compared to that benchmark. Holding the base fixed and escalating it forward means that a strong early year does not raise the bar against the Company in later years.

Q. Why O&M per customer, and why customer count rather than load?

A. First, this aligns with guidance from PURA in Docket No. 21-05-15RE02, where its pending July 14, 2025, proposed final decision called for reporting certain cost efficiency metrics on a per customer basis. O&M is driven by customers and the physical system, service, billing, inspections, vegetation, and the assets themselves, not by how much energy flows through the wires. Measuring per customer neutralizes growth, so the metric reads as efficiency rather than scale. Using customer count rather than load also keeps weather and economic swings out of the measure; load would rise and fall with hot summers and cold winters and would require a separate weather-normalization study, which is exactly the kind of complexity this design avoids.

Q. What is included in controllable, base-rate O&M?

A. It is the Company's non-tracked, line-of-business O&M excluding expenses that are recovered separately or are not reasonably subject to annual management control, such as vegetation management, storm costs, retiree benefit costs, and pension expenses. The Company proposes to call this measure Core Operating Expense rather than 'controllable,' because it is defined by what it includes rather than by a contested label, and because a fixed, filing-consistent definition is what keeps the metric sound.

Q. How does the ratchet move the dividend level?

A. It moves in small, asymmetric steps. The level starts at a set point; a year that beats the benchmark steps it up by a larger increment, and a year that misses steps it down by half that increment. The level never falls below its 0.30 percent starting level, so it stays immaterial to the revenue requirement. The level is durable within the plan term, a beat that lifts it stays lifted rather than resetting, so the dividend reflects sustained performance rather than a single year. At the end of the plan term the level resets, because a new rate case sets new rates.

Q. Why is the ratchet asymmetric, and weighted toward the customer?

A. Two reasons. First, the dividend is designed as an affordability measure, so when it moves, it should favor the customer. Second, the downside

step is a guardrail. If the Company has a difficult year, easing the dividend by only a half-step, rather than erasing it, keeps the mechanism from moving quickly against customer interest and keeps the level from being something a single off year wipes out. The asymmetry also keeps the dividend small enough that it cannot be turned into a large swing that would distort the plan. Further, the downside scale is small, meaning that achievement of efficiency will always be the better financial outcome.

Q. The design object of easing the dividend downward when the Company is less efficient has the potential to have customers bear the consequence of that inefficiency. Is there an adjustment to the design that answers that concern?

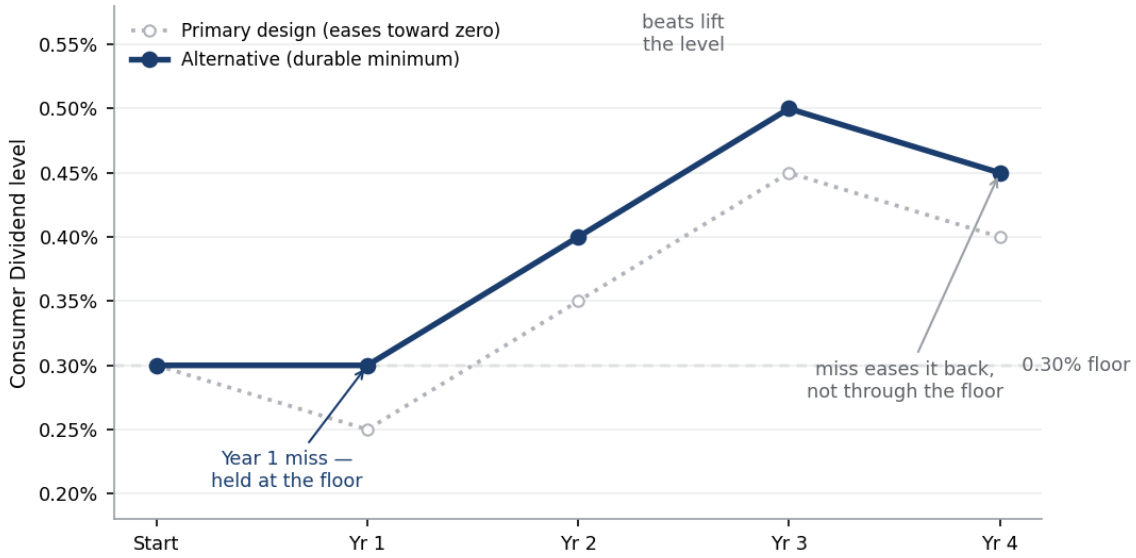
A. Yes, and the concern is a fair one. A customer should not end up worse off because the Company had an inefficient year. The Company therefore proposes a mechanism in which the dividend can never ease below its starting level. The ratchet works exactly as we have described, a beat steps the level up, a miss steps it down by half, except that the floor is set at the starting Consumer Dividend rather than at zero. The starting benefit becomes a durable minimum. A customer keeps at least the day-one dividend for the life of the plan, the dividend can still climb with sustained efficiency, and a miss can walk the level back down toward that minimum, but never through it. Only the downside is bounded, at the starting level instead of zero.

Q. Does the Company view it as appropriate to design the S-factor in a manner that does not allow the mechanism to ease the dividend below its starting level?

A. Yes. A fully symmetric version has its own logic, it gives back on the upside and eases on the downside in equal measure. However, this design is set to enhance affordability, which is why the Company is setting it at the top end of the recommended range, and ensuring the dividend never eases below its starting level to provide a minimum benefit that customers can count on. This is the better fit for a mechanism whose purpose is affordability. Framed this way, the design preserves the plan's economic signal, the dividend still grows whenever the Company finds efficiencies, so the incentive to outperform is undiminished, while adding a floor that protects an affordability design for ratepayers in the years between rate cases when those efficiencies do not materialize. The illustration below traces a representative path of how the proposed S-factor would work: a first-year miss that holds at the starting level rather than easing below it, two years of beats that lift the level, and a later miss that eases it back without breaching the floor.

Figure 6: Illustrative Ratchet Path

A first-year miss holds the dividend at its 0.30% starting level rather than easing below it; subsequent beats lift the level; a later miss eases it back, but never through the floor. The floor-below 3.0 is shown only for comparison; the floor-at-starting-level design is the Company's proposal.



4. Sizing and Scale

Q. How did you arrive at the starting level?

A. From the Company's own benchmarking, using the methodology its consultant applied. The final benchmarking study supports a starting level consistent with the range regulators have adopted across comparable jurisdictions — on the order of 0.15 to 0.6 percent. The Company proposes 0.30 percent. The starting level ties the sharing the Company offers to the efficiency opportunity the benchmarking identifies and gives the Company something concrete to work toward over the plan. The starting level remains a stretch, it ties the sharing the Company offers

to the efficiency opportunity the benchmarking identifies, set deliberately at the customer-favorable end, and gives the Company something concrete to work toward over the plan[42].

Q. How large is this in dollars?

A. Modest by design — on the order of a few dollars per customer per year, and well under one percent of Core Operating Expense in total. The amount is intentionally small. The Consumer Dividend is a visible, directional signal that efficiency is being shared, not a transfer payment, and keeping it small is what keeps it immaterial to the primary goal of efficient spending of the existing revenue requirement and limits or eliminates any incentive to manipulate it.

Q. Is an amount that small worth doing?

A. Yes. Its value is not in its size, but in what it does. It gives all customers a concrete benefit from the plan, and it gives PURA a mechanism that shares efficiency without muting core economic signals. This is appropriate for a first generation PBR model. While the amount is small on a per-customer basis, across the full customer base, this is projected

[42] Exhibit CLP-PBR-3

to total over a million dollars annually, which is a meaningful indication that the Company is seeking to share back these benefits with customers.

5. Guardrails

Q. Does easing the dividend on a miss weaken the very incentive a performance plan is supposed to create?

A. The answer is that the dividend's downside contains a guardrail, and due to its size it would not be the Company's primary efficiency incentive. The primary incentives in the plan lie elsewhere — the adjustment formula, the budget the Company must live within, and the efficiency needed during the stay-out itself. The Consumer Dividend is an affordability measure layered on top, designed to add an additional earning sharing mechanism in ratepayers' favor. The downside risk balances the act of adding in a mechanism that would share earnings even if the Company is earning below the allowed rate of return.

Q. Does this design somewhat push against the economics relative to the overall performance plan?

A. In one sense, yes. A performance mechanism that typically grows when the Company does well, and eases when it struggles, is the reverse of a penalty regime. This isn't a performance metric, however, but an earning sharing mechanism aimed at affordability. An earnings-sharing works by operating below the authorized return rather than above it. When the Company holds costs below inflation, customers share in that

immediately, instead of waiting for the Company to exceed its allowed return, which almost never happens.

Q. How does it relate to the cost-reporting metrics the Company proposes?

A. The trigger uses the same Core Operating Expense per customer measure that the Company proposes to report under the cost-efficiency metrics carried forward from PURA's prior proceeding. Those metrics are proposed as reporting-only — tracked and trended, with no targets or penalties attached. The Consumer Dividend is the one place that a reporting metric is given a modest, concrete, customer-facing consequence.

Q. Why should PURA adopt the Consumer Dividend as the S-Factor in this plan?

A. Because it aligns the Company, its customers, and PURA around the same outcome. When the Company holds the costs it controls below inflation, customers see a benefit on the bill; when the Company is under pressure, the mechanism gives modest relief rather than adding to the burden. The S-Factor is small, bounded floored and has guardrails, so it cannot distort the plan or threaten the Company's financial integrity. It makes a simple, durable point that an affordability case should be able to make: that a well-run utility and its customers are on the same side.

Q. To reiterate, how is the Consumer Dividend different from the sharing the Company already does?

A. This is the one I would highlight, because it reaches something the existing tools do not. Connecticut already has an earnings-sharing mechanism. When the Company earns *above* its authorized return, the excess is shared with customers. That mechanism does important work — but it only operates above the line. It does nothing when the Company is earning at or below its allowed return.

The consumer dividend is built for exactly that space. Because of regulatory lag, a utility is often earning *below* its authorized return even when it is running efficiently — and this is why earning sharing is rarely triggered because there are no excess earnings. But efficiency and earnings are not the same thing. A company can be genuinely efficient and still under-earning. The consumer dividend captures that. It measures the costs the Company controls — defined in the plan as Core Operating Expense — on a per-customer basis against a benchmark escalated by the plan's composite input-cost index, and when the Company beats that benchmark — when it is actually getting more efficient — customers receive a dividend, funded by shareholders, floored at 0.3 basis points so it can never become a surcharge to customers. It ticks up when the Company delivers efficiency, whether or not there are

excess earnings to share. The Company's independent PBR expert, reviewing the design, reached the same conclusion: it benefits customers because it delivers an immediate share of expected efficiency gains during the plan term, rather than requiring customers to wait for the next rate case to capture them[43].

That is what makes it the natural complement to the performance-based mechanism. Performance-based regulation, on the O&M side, is what produces the efficiency, and the consumer dividend is how customers see a share of it. The existing mechanism shares profit *above* the allowed return; the consumer dividend shares efficiency *below* it. The two cover different ground, and together they close a gap. I would not overstate its size — it is a deliberately modest, targeted mechanism, not the answer to affordability by itself — but it is a real, earned give to every customer, and it makes the discipline at the center of this testimony visible on the bill. The detailed design is addressed separately.

[43] Exhibit CLP-PBR-1

VI. CONCLUSION

Q. Drawing the framework and the Company's specific proposals together, why is this an affordable plan?

A. Because affordability, properly understood, is not the least amount of money PURA can authorize in a single year. Instead, it is the appropriate level of investment that is effective, in that it maintains a safe and reliable grid, and efficient, in that each dollar spent buys a commensurate benefit, paired with concrete protections for the customers who pay for it. The framework I have described is the lens through which I have evaluated this case. Measured against it, this plan satisfies affordability on each of the three dimensions the framework requires — Budget, Burden, and Balance — at once.

On Budget and Balance — the Company's and the regulator's perspectives — the investment itself is calibrated. The plan places CL&P's distribution investment in the middle range of the Investment Calibration Framework, correcting the drift toward the underinvestment tail I describe in Section III rather than pushing toward either failure mode. That calibration is not asserted; it is tested. The capital plan satisfies the Budget discipline, expenditures are disciplined, justified, and escalated against an appropriate inflation measure, and the incremental reliability investment is subjected to the Company's benefit-cost analysis, so that

each dollar is shown to purchase a commensurate reliability benefit. That is the operational form of the standard I set out earlier: the question is not how much is spent, but whether each dollar invested yields a meaningful customer benefit. The project-level demonstrations sit with the system-planning panel and the benefit-cost analysis with the Company's engineering witness; my point is that the plan is built to be measured, not merely funded.

On Burden — the customer's perspective — the plan pairs that investment with direct affordability protection for the households most exposed. It continues and proposes[44] to update a five-tier low-income discount rate designed to hold participating customers' energy burden to roughly six percent. And it introduces new heat pump and economic-development rates that work on affordability from both ends: they lower costs directly for the customers who take them, and they lower costs for *all* customers by adding load across which the system's fixed costs are spread. That second effect is not incidental — the size of the base over which fixed costs are spread is itself an affordability lever. Load growth pushes per-customer costs down; an eroding base pushes them up. Growing load, and defending the commercial and industrial base the

[44] Exhibit CLP-CUSTOMER-1

Company already serves, is therefore an affordability strategy in its own right.

Lastly, the plan is structured to *hold* that calibration over time and to share the gains with customers. The proposed PBMRP funds the capital program through an allowance capped at the approved forecast, reconciled annually, but only downward. Customers pay the lesser of the forecast or the cost of plant actually placed in service, and spending above the forecast is the Company's risk, not the customer's. That design is deliberate and, in my view, affordability-enhancing in its own right: a fixed capital envelope does not invite overspending, it imposes discipline, requiring the Company to make the most economical decisions for customers within a defined budget, against its reliability commitments and SAIDI/SAIFI performance obligations. The plan's O&M mechanism rewards operational efficiency rather than spending. And the Consumer Dividend returns a share of realized efficiencies directly to customers when the Company out-perform its Core Operating Expense benchmark, so that when the Company does well on cost, customers share in it, beneath the authorized return. This is the link that has been missing in Connecticut: a structure that funds necessary investment, disciplines it with a fixed cap, and pays customers back when efficiency is achieved.

Taken together, the plan delivers calibrated investment, direct protection for vulnerable customers, and a structural discipline that shares efficiency with ratepayers. That is what makes it affordable — not from one vantage point, but from the customer's and the regulator's, at the same time.

Q. Does this conclude your testimony?

A. Yes.