STATE OF NEW HAMPSHIRE

BEFORE THE

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 24-070

REQUEST FOR CHANGE IN RATES

DIRECT TESTIMONY OF

Douglas W. Foley, Robert S. Coates, Jr., and Douglas P. Horton

Case Overview

On behalf of Public Service Company of New Hampshire

d/b/a Eversource Energy

June 11, 2024

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PETITION OF PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE d/b/a EVERSOURCE ENERGY

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I. INTRODUCTION

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

A. My name is Douglas W. Foley. Currently, I am President of New Hampshire Electric Operations. My business address is 780 North Commercial Street, Manchester, New Hampshire. Effective July 7, 2024, I will be transitioning to the role of President, Electric Operations – Massachusetts and my colleague, Robert S. Coates, Jr., will be taking over the role of President, Electric Operations – New Hampshire. In light of this pending transition, we are co-sponsoring this testimony along with Mr. Douglas P. Horton.

Q. What are your principal responsibilities in this position?

A. As the President of New Hampshire Electric Operations, I am responsible for assuring that Public Service Company of New Hampshire ("PSNH" or the "Company") provides safe and reliable electric service to over half a million customers in 211 cities and towns throughout New Hampshire, as well as for overseeing the construction, operation and maintenance of the Company's electric distribution infrastructure in the state.

Q. Please summarize your professional and educational background.

A. I have been employed by Eversource Energy Service Company ("ESC") and its affiliates for over 35 years, holding various positions of increasing responsibility in the organization. I have held the position of President, Electric Operations – New Hampshire since August 2021. I have a Bachelor of Science degree in Electrical and Electronics Engineering Technology from the Wentworth Institute of Technology, as well as a Master of Business Administration degree from Anna Maria College and a Master of Power System Management degree from Worcester Polytechnic Institute.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission") or other regulatory agencies?

A. I have not testified before the Commission previously, but I have testified before the Massachusetts Department of Public Utilities in various proceedings related to electric utility operations and cost recovery.

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

A. My name is Robert S. Coates. Jr. I am currently Vice President of Project Management and Construction for Eversource Energy. Effective July 7, 2024, I will take over the role of President, Electric Operations – New Hampshire. In that role, my business address will be 780 North Commercial Street, Manchester, New Hampshire.

Q. What are your principal responsibilities in your current position?

A. As the Vice President of Project Management and Construction, I am responsible for overseeing major Transmission and Distribution projects and capital construction across the Eversource Energy service territory, including New Hampshire. In addition, I provide storm-restoration leadership across the Eversource Energy enterprise, including New Hampshire.

Q. Please summarize your professional and educational background.

A. I have been employed by ESC and its affiliates for over 36 years, holding various leadership positions in the safety and electric operation organizations. I have held the position of Vice President of Project Management and Construction since December 2021 and have been an Officer within the Electric Operations organization for over a decade. I have a Bachelor of Science degree in Occupational Safety and Health from the University of New Haven and a Master of Business Administration degree from American International College.

Q. Have you previously testified before the Commission or other regulatory agencies?

A. I have not testified before the Commission previously, however I have testified in other cases before the Massachusetts Department of Public Utilities.

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

A. My name is Douglas P. Horton. I am Vice President, Distribution Rates & Regulatory Requirements for ESC. My business address is 247 Station Drive, Westwood, Massachusetts 02090.

Q. What are your principal responsibilities in this position?

A. ESC provides centralized services to the natural gas and electric operating subsidiaries of Eversource Energy. In this role, I have overall responsibility for rates and rate-related policies and procedures, as well as preparation and presentation of regulatory filings made by the Eversource Energy operating affiliates to the respective regulatory authorities in Connecticut, Massachusetts and New Hampshire. In this proceeding, I am responsible for supervising and presenting the Company's calculations and supporting exhibits pertaining to the request for approval of temporary and permanent base distribution rates and approval of the Company's Performance Based Ratemaking ("PBR") plan.

Q. Please summarize your professional and educational background.

A. I graduated from Bentley College (now Bentley University) in Waltham, Massachusetts in 2003 with a Bachelor of Science degree. In 2007, I graduated from Bentley's McCallum Graduate School of Business with a Master of Business Administration. I was hired by NSTAR Electric Company as a Senior Financial Planning Analyst in August 2007, and promoted to Project Manager, Smart Grid in March 2010. In 2012, I was promoted to Manager, Revenue Requirements, Massachusetts and was subsequently promoted to Director, Revenue Requirements, Massachusetts, in February 2015. I was promoted to Vice President, Distribution Rates & Regulatory Requirements in December 2018.

Q. Have you previously testified before the Commission or other regulatory agencies?

A. Yes. I testified before the Commission in support of the Company's Petition for Permanent Rates in Docket No. DE 19-057, as well as in the docket pertaining to the audit of

Company's generation divestiture costs, Docket No. DE 20-005, and the Company's joint petition with Consolidated Communications of Northern New England Company, LLC for approval of a pole asset transfer, Docket No. DE 21-020. In addition, I have testified on numerous occasions before other regulatory commissions, including the Massachusetts Department of Public Utilities and the Connecticut Public Utilities Regulatory Authority.

Q. What is the purpose of your testimony?

A. The purpose of our joint testimony is to provide the Commission with an overview of PSNH's request for new distribution rates and proposed performance-based ratemaking ("PBR") Plan. The Company is devoted to its core mission of ensuring the continued safe and reliable delivery of electric service to all its New Hampshire customers. To achieve this objective, the Company's filing proposes a change in base distribution rates, along with implementation of a balanced PBR Plan that will enable the Company to continue to enhance reliability and resiliency for residential and business customers, minimize administrative burdens by reducing regulatory filings, introduce a series of new performance metrics and mitigate rate impacts for customers.

The Company's filing includes proposed permanent rate tariffs with an effective date of August 1, 2024. The Company anticipates that the Commission will suspend the proposed permanent rate tariffs, and therefore the Company proposes to implement the approved permanent rates effective August 1, 2025, in order to align new permanent rates with other anticipated rate changes that will occur on that date. Lastly, the Company has included a request for a temporary rate change to take effect on August 1, 2024, as described and supported in the materials accompanying this filing. An August 1st effective date for temporary rates is consistent with the directive of RSA 378:27 to "*immediately* fix, determine, and prescribe for the duration of said [rate] proceeding reasonable temporary rates . . . to yield *not less than a reasonable return*" (emphasis added). The Company has included the requisite reports as a part of this filing for the Commission and the New Hampshire Department of Energy ("DOE") to rely upon. Given the ample support provided for the Company's temporary rate relief request, it will be possible to implement temporary rates on August 1, 2024, so that the 12-month proceeding can culminate in permanent rates on August 1, 2025, coincident with other rate changes so that customers experience only one rate change. The August 1, 2024 effective date for temporary rates is achievable given the less stringent standard for review and investigation required for setting temporary rates. (*See* Order No. 26,855 at 3).

The Company's last requested distribution rate increase was filed in 2019, in Docket No. DE 19-057. Since 2019, PSNH has consistently provided customers with high level of service reliability, has made substantial investments in distribution infrastructure, has implemented new customer services, including the New Start program to provide assistance to lower-income customers, and has steadily navigated through extraordinary challenges, including the COVID-19 pandemic.

Our joint testimony addresses the following topics: (1) the factors that are driving changes in the Company's operating environment and shaping the ratemaking proposals presented in this case; and (2) an overview of the Company's distribution rate request and key proposals that are included therein. In this context, our testimony presents the Company's proposed PBR Plan and discusses the reasons that adoption of the PBR Plan makes sense for customers.

Q. Are you presenting any attachments in addition to your testimony?

A. Yes. Mr. Horton is presenting the following attachments in support of the proposed PBR plan:

Attachment Designation	Purpose/Description
Attachment ES-DPH-1	Illustrative Performance Based Revenue Adjustment
Attachment ES-DPH-2	K-bar Capital Allowance

Q. Is the Company's temporary and permanent rate request supported by testimony from additional witnesses?

A. Yes. The Company is presenting a comprehensive rate filing supported by all of the information required by the Puc 1600 rules, including testimony and exhibits demonstrating the need for temporary and permanent rate relief, as well as the Commission's standard filing requirements that accompany such a request. In addition to this testimony, the Company's request is supported by testimony from the following Company witnesses:

- Temporary Rate Revenue-Requirement Analysis: Ashley N. Botelho, Director of Revenue Requirements, Distribution, for ESC, and Yi-An Chen, Director of Revenue Requirements, for New Hampshire, present the Company's revenue requirement analysis to support temporary rates effective August 1, 2024.

- Permanent Rate Revenue-Requirement Analysis: Ashley N. Botelho, Director of Revenue Requirements, Distribution, for ESC, and Yi-An Chen, Director of Revenue Requirements, for New Hampshire, present the Company's revenue-requirement analysis and associated rate proposals, including a proposal for recovery of storm costs. Their testimony also proposes changes in existing rate mechanisms that would move recovery from the existing reconciling mechanisms to base rates, including costs associated with property taxes, vegetation management, long-term debt for storm costs and rate case expenses. Their testimony also proposes to eliminate the Pole Plant Adjustment Mechanism and lost base revenues ("LBR") associated with energy efficiency and net metering, should the Commission approve the PBR Plan in this proceeding.

- Performance Based Ratemaking Theory: Mark Kolesar, Managing Principal at Kolesar Buchanan & Associates Ltd. and Dr. Agustin J. Ros, Senior Managing Director at Ankura and Adjunct Professor at Brandeis University, International School of Business, present testimony and benchmarking studies to support the proposed PBR Plan.

- Performance Based Ratemaking Metrics: Robert S. Coates, Jr., currently Vice President of Project Management and Construction for Eversource Energy, Paul R. Renaud, Vice President of Distribution Engineering for ESC, Brian Dickie, Vice President New Hampshire Electric System Operations, Warren Boutin, Vice President Customer Grid Electrification Solutions and Experience, Shamus O'Brien, Director of Voice of the Customer and Customer Experience Strategy, Amy Findlay, Manager of Energy Efficiency jointly present testimony supporting the performance metrics that the Company is proposing under the PBR plan.

- Distribution System Planning and Solutions: Lavelle A. Freeman, Director of Distribution System Planning for ESC, Jennifer A. Schilling, Vice President of Grid Modernization for ESC, Dr. Elli Ntakou, Manager of Reliability & Resiliency Planning at ESC, Dr. Gerhard Walker, Manager for Advanced Forecasting and Modeling for ESC, and Paul R. Renaud, Vice President of Distribution Engineering for ESC present testimony discussing and supporting the Distribution Solutions Plan ("DSP") which describes the forecasting and planning process to meet the demands on the PSNH electric system.

- Vegetation Management: Robert D. Allen, Manager of Vegetation Coordination, Strategy and Innovation, provides testimony on the Company's proposals relating to the vegetation-management activities undertaken for system reliability and resiliency objectives on the PSNH distribution system.

- Customer Operations and Digital Strategy: Daniel M. Traynor, Director of Credit and Collections, and Christopher G. Kishimoto jointly present the Company's experience implementing the New Start and Fee Free programs, which were approved as part of the Company's last rate case in Docket No. DE 19-057.

- Capital Planning and Additions: Leanne M. Landry, Director of Investment Planning for ESC, James J. Devereaux, Manager of New Hampshire Budgets and Investment Planning, and Brian Dickie, Vice President New Hampshire Electric System Operations, jointly present testimony in support of the Company's capital additions completed through December 31, 2024, and proposed for inclusion in rate base in this proceeding.

- Depreciation: John J. Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, presents the depreciation study performed for PSNH to calculate annual depreciation accrual rates by account as of December 31, 2023, for all electric plant.

- Allocated Cost of Service Study and Marginal Cost of Service Study: Amparo Nieto, Principal at the Energy Practice of Charles River Associates, provides two pieces of testimony, the first in support of the allocated cost of service study and the second in support of the marginal cost of service study, which were both used by PSNH in developing its proposed distribution rates.

- Cost of Capital: Vincent V. Rea, Managing Director of Regulatory Finance Associates, LLC, an independent financial and regulatory consulting firm, presents evidence and provides a recommendation regarding the Company's cost of capital, including the proposed return on equity ("ROE") and his assessment of the capital structure to be used for ratemaking purposes.

- Temporary Rates and Tariff Changes: Edward A. Davis, Director of Rates for ESC, presents the proposed changes to distribution rates and corresponding tariff changes associated with the revenue requirement for temporary rates.

- Permanent Rates and Tariff Changes: Edward A. Davis, Director of Rates for ESC, presents the proposed changes to distribution rates and corresponding tariff changes associated with the revenue requirement for permanent rates.

III. PSNH ORGANIZATION AND OPERATIONAL STRUCTURE

Q. Please describe the Company and its current organizational structure.

A. Eversource Energy's electric distribution business consists of PSNH in New Hampshire, Connecticut Light and Power Company ("CL&P") in Connecticut, and NSTAR Electric Company in Massachusetts -- all of which are engaged in the distribution of electricity to retail customers in their respective states. Eversource Energy's water business includes Aquarion Water Company of New Hampshire, Inc., which provides water service in the towns of Hampton, North Hampton and Rye, New Hampshire; and Abenaki Water Company, which provides water service in the towns of Belmont, Bow, the Bretton Woods area of Carroll, and Gilford, as well as Aquarion Water Company of Massachusetts, Inc., Aquarion Water of Connecticut, Inc., and Torrington Water Company in Connecticut. Eversource Energy also has natural gas delivery companies in Massachusetts and Connecticut.

PSNH's distribution business consists primarily of the delivery and sale of electricity to its residential, commercial, municipal and industrial customers. As of December 31, 2023, PSNH furnished retail franchise electric service to approximately 539,000 retail customers in 211 cities and towns in New Hampshire. PSNH's electric system consists of approximately 1,050 miles of transmission lines, approximately 14,000 miles of overhead and underground distribution lines, and 149 substations and related facilities throughout the service territory.

As of December 31, 2023, Eversource Energy employed a total of 10,171 employees, including 830 employed directly by PSNH. Approximately 49 percent of Eversource Energy's employees are members of the International Brotherhood of Electrical Workers ("IBEW"), the Utility Workers Union of America or The United Steelworkers and are covered by collective bargaining agreements. The majority of PSNH's union employees are covered by a single collective-bargaining agreement with IBEW Local 1837.

Q. Are there any accomplishments of PSNH and its employees that you would like to highlight?

A. Yes. PSNH and its employees remain dedicated to giving back to the communities we serve through employee volunteerism, charitable donations and civic involvement. In

2023, PSNH employees volunteered nearly 4,000 hours of time to local New Hampshire non-profit organizations, helping to enhance the quality of life in the communities served by the Company. PSNH generously donated more than $715,000 to organizations throughout the state including the United Way, Easterseals New Hampshire, the Neighbor Helping Neighbor Fund, Special Olympics New Hampshire, See Science Center and many other organizations.

PSNH also continues to place particular emphasis on partnering with non-profit agencies and the community college system to foster workforce development, as demonstrated by our partnership with FIRST Robotics and the Governor's Cup competition. In the spirit of workforce development, PSNH provides resources and funding to New Hampshire community schools for science, technology, engineering, and mathematics ("STEM") educational initiatives and STEM camps. The Company also continues to be actively involved with local Chambers of Commerce organizations to help foster and promote a healthy local economy.

II. FACTORS AFFECTING THE DISTRIBUTION BUSINESS

Q. How would you describe the current operating environment and what is PSNH's vision for the future?

A. The confluence of operating dynamics confronting electric distribution companies at this stage is unprecedented in the Company's experience. The operating environment for electric utilities is extraordinarily challenging, influenced by: (1) regional energy policy motivating changes in the nature, scale and technological intricacy of electric operations;

(2) the emergence, adoption and expansion of new technologies not contemplated by the existing design of the electric system or supported by PSNH's business enterprise systems; (3) evolving customer expectations and demand for broader use of and engagement with digital technologies; (4) challenges in hiring, training and retaining skilled personnel willing to make the types of personal sacrifices that storm restoration requires; (5) substantial quantities of aging infrastructure that must be replaced, upgraded and maintained to meet all other expectations; and (6) changing weather patterns with frequent winter and summer storms with significant impact. As an electric distribution company responsible for meeting the expectations of customers, these challenges are both sobering and galvanizing, but in either case – thoroughly resource consuming.

From generation to the customer meter, the pace of technology development has resulted in a sustained, thoroughly dynamic operating environment. These technological advances include the growing adoption of distributed sources of energy, such as wind and solar, as well as advances in energy storage, distribution automation solutions and microgrids. Energy efficiency programming has continued to prove a popular vehicle for customers to lower their energy bills and modernize their homes and businesses. At the same time, customer expectations regarding reliable and resilient electric service continue to grow as the economy depends more and more on uninterrupted electrical service. Moreover, in today's highly connected digital world, customers increasingly expect to be served in a digital fashion by all of their service providers, including utilities. All of these factors are converging to create pressure on the Company to evolve the distribution system and the attendant utility services in a manner that will accommodate these changes and advance further evolution.

PSNH recognizes that, fundamentally, the economic and environmental health of the New Hampshire communities existing within the Company's service territory depend upon the availability of safe, reliable, sustainable and affordable energy resources. Conversely, the Company's ability to provide those resources is a function of capital investment and the skill and dedication of the workforce. The Company needs to make substantial – and continuous – investment in the distribution system just to maintain current levels of system reliability, resiliency, and safety, in the face of aging infrastructure and asset condition. Even more will be required to raise the system capabilities to the level necessary to meet the expectations of New Hampshire's residents, businesses, municipalities and state policy makers. For this task, the Company needs highly skilled, dedicated employees at all levels of the organization– from the crews in the field that build and restore the system, to employees managing information systems and engineering capital projects, among many other areas of importance. Adopting PBR is a pivotal piece of the puzzle in that it enables the Company to rise to meet its operating mission under these constantly evolving circumstances, without the administrative burden of frequent regulatory proceedings posed for the Company, regulators and key New Hampshire stakeholders, where it is necessary for the Company to obtain incremental revenue support for operations. In this context, implementation of the Company's proposed PBR Plan will deliver tangible value to PSNH customers with efficiency and reduced administrative cost for all interested parties.

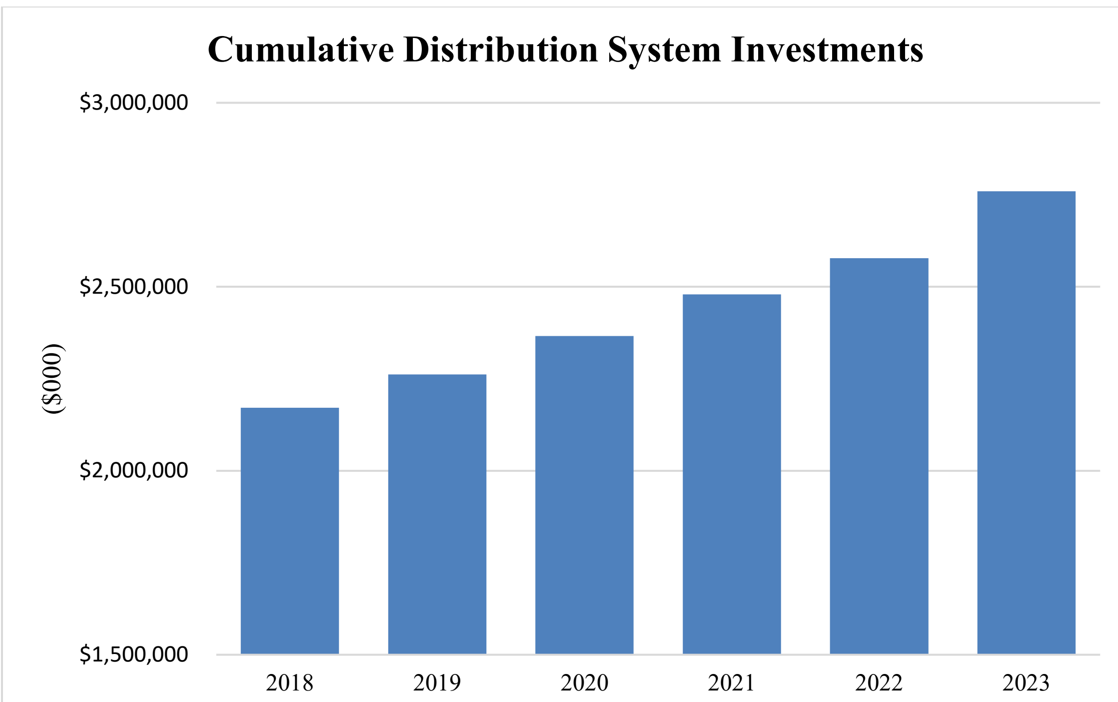
Moving forward, the Company envisions that today's operating dynamics will continue to evolve bringing even greater technological complexity; eminently larger infrastructure requirements; and the need to find and develop talent to manage the enterprise to meet the daily expectations of customers. The System Planning and Solutions testimony presented by the Company in this proceeding provides insight into how the Company is planning for the future, with particular focus on building capabilities to meet current and future service requirements in a safe and reliable manner. PBR is critical in this operating environment because it would provide the Company with the flexibility to focus on operations, customer service and meeting the expectations of customers, while providing the essential revenue support necessary to make ends meet and, conversely, a tool for mitigating bill impacts for customers.

Q. Has the Company made substantial capital investments since the 2019 Rate Case?

A. Yes. The Company has made significant infrastructure investments to maintain and improve the reliability and resiliency of the distribution system that directly benefit New Hampshire customers in supporting their daily activities, as well as the safe and expeditious restoration of power following storm events. The Company's investment in distribution infrastructure is important for the New Hampshire economy and its many communities. For example, the Company's efforts to develop, upgrade and reinforce distribution infrastructure supports local jobs and generates local property-tax revenue.

As shown in Figure 1 below, the Company's plant additions in the years since the 2019 Rate Case have been on target with plans and projections presented in that case and sufficient to meet the demands of an aging system.

<u>Figure 1: Distribution Plant in Service</u>



Q. Has the Company taken steps to control operating and maintenance expense?

A. Yes, while the Company has progressed in its work to develop, upgrade and reinforce distribution infrastructure, the Company has worked diligently to control operating expense. Some of the initiatives that enabled operating efficiencies and associated cost reductions include using more data analytics to streamline and automate reliability reporting and other work processes; fleet standardization; contract renegotiations;

leveraging of supply chain partnerships and use of contractors of choice for engineering work, among many other initiatives across all functions of ESC and the Company.

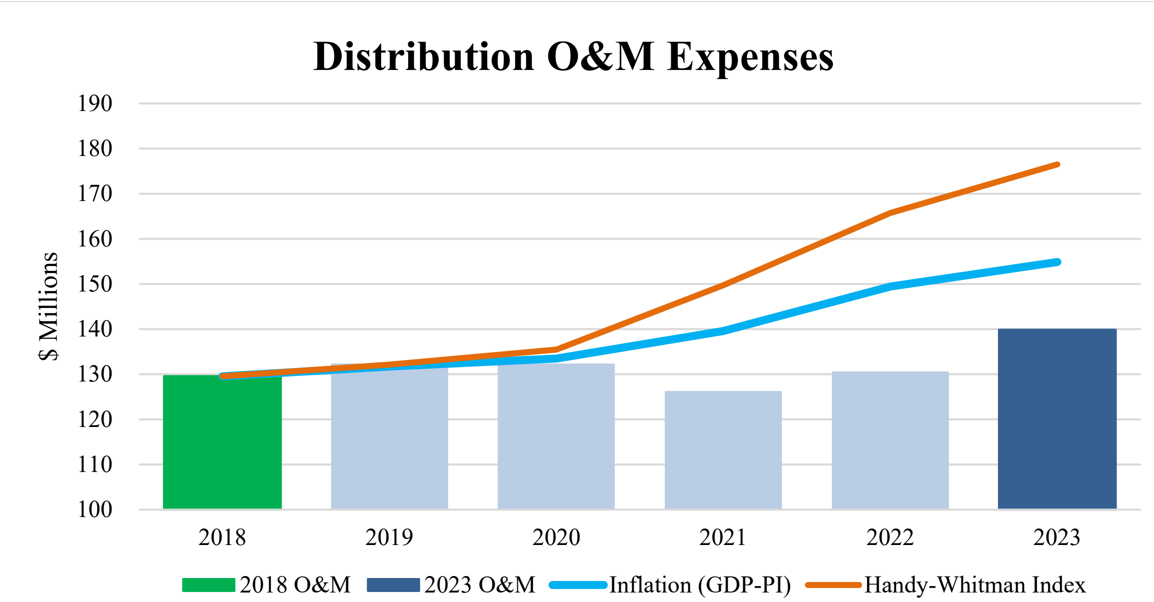
Excluding storm costs, vegetation management and enterprise Information Technology ("IT") systems development, the Company held distribution operation and maintenance ("O&M") costs steady and stable, amounting to a compound annual growth rate since 2018 of 1.54 percent, subject to year-to year-fluctuations to meet operating conditions. This track record was achieved despite pressure from rising inflation that grew at a compound annual growth rate of 3.64 percent over that same time period. Over the last two years alone, general inflation as measured by GDP-PI grew at a rate of 5.33 percent, a factor that impacts all businesses. Although PSNH is no exception, the Company has worked hard to mitigate the impacts of inflation and other factors on the cost of service to the direct benefit of customers.

Another way to put the Company's O&M spending into context is by utilizing the Handy-Whitman Index ("HWI"). The HWI is compiled and published by Whitman, Requardt and Associates and is available for purchase under a subscription service.[1] This index calculates the cost trends for construction among different types of utilities (i.e., electric, gas, and water utilities) for each of the six geographical regions in the United States (North Atlantic, South Atlantic, North Central, South Central, Plateau, and Pacific regions). The HWI illustrates that recent construction costs in the electric industry in the

1 Whitman, Requardt, and Associates. The Handy-Whitman Index of Public Utility Construction Costs. July 2024

North Atlantic region have sharply increased at a compound annual growth rate of 6.36 percent from 2018 through 2023. Although the vast majority of the Company's work processes are construction focused, the Company has successfully controlled operating and maintenance ("O&M") cost well below this threshold.

Figure 2: PSNH – Distribution O&M



O&M amounts as filed annually in the PUC F1, excluding non-major storm costs, vegetation management and enterprise IT projects

Q. Why has the Company excluded storm costs, vegetation management and enterprise IT expense from the O&M expense analysis presented in Figure 2, above?

A. Each year, as part of its one-year operating plan and long-range planning process, the Company presses the business units to find any and all operating efficiencies that will enable it to improve work and response times, leverage technology and enhance employee training and capabilities, with the ultimate goal to do more with less. Both the overall

Eversource Energy organization and PSNH take great pride in the ability to provide excellent customer service at affordable rates and is committed to controlling operating costs to whatever extent possible. However, there are key factors that impact the level of operating expense incurred in each year that cannot be materially mitigated or eliminated through efficiency gains, even with best practices. The primary examples of these cost items are storm costs, vegetation-management expense and enterprise IT expense.

Enterprise IT expense is a unique cost category that is within the organization's control on a project-by-project basis, but is also broadly influenced on a macro level by external forces requiring Eversource Energy to work constantly to keep its systems safe from cybersecurity threats and to keep its technology platform current with technologies available (and serviced by) the marketplace, as well as technologies used by business partners and even customers. Enterprise IT costs are incurred on a shared basis across the organization and recorded as plant additions on the books of the Eversource Service Company, as opposed to directly on PSNH's balance sheet. In cases where an enterprise IT solution is able to serve multiple operating companies, the capital costs incurred by ESC are charged out to the benefiting operating companies as annual expense, rather than as capital costs. As a shared cost, PSNH benefits from the availability of state-of-the art cybersecurity protections and computer automation, without having to bear the full costs of systems that are complex and costly to create, install and maintain. However, when recorded on the books of ESC and charged to the operating companies, the costs appear as an operating expense on the Company's books, rather than in capital-related accounts (e.g., depreciation and amortization) that would reflect the true nature of the cost.

Similarly, the cost of responding to major and non-major storm damage is a function of the increasing frequency and intensity of weather systems that impact New Hampshire as major or "non-major" storm events. "Non-major" weather events are weather systems or weather patterns that cause damage to the distribution system, but do not rise to the level of a major storm event. Non-major weather events are equally unpredictable and beyond the control of the Company, and when those weather events occur, the Company incurs the cost of restoring power as an incremental expense that is not recovered through rates, except to the extent occurring in the test year in the last rate case. When major and non-major storm patterns occur and cause system damage, the Company's need to respond is absolute. As a result, major and non-major storm costs are a cost category that the Company must plan for and work to handle with efficiency, but are not a category that can be avoided, curtailed or controlled to any material degree. In 2018, the Company incurred roughly \$2.7 million associated with non-major storm costs, whereas in 2023, the costs had risen to roughly \$13 million, as reflected in Account 593140 (the costs of major storm events are deferred to a regulatory account). These are costs that the Company absorbs as O&M expense to the extent that the costs exceed the adjusted test year amount.

With respect to vegetation management, the increase in recorded expense in 2023 as compared to 2018 was roughly \$17 million -- all attributable to a change in accounting practice rather than a change in the level of expenditures. As explained in the Company's prior rate case in 2018, the Company had been recording certain vegetation management costs as capital-related costs that -- going forward -- were recorded as expense, causing an apparent increase in vegetation-management cost over that time period. Specifically, in Docket No. DE 18-177, the Commission authorized the continuation the Company's Reliability Enhancement Plan ("REP") for calendar year 2019 in a manner that accounted for certain changes in tree maintenance activities and the continuation of the Company's Troubleshooter program. Among other items, the Company requested that the costs associated with the enhanced tree trimming ("ETT"), hazard tree removal and full-width right-of-way clearing, totaling $16.8 million, be treated as expense items rather than capitalized costs going forward within the REP. This change accounts for the change in O&M expense over the period 2018 to 2023.

Q. Have the Company's capital investments had a measurable impact on system reliability?

A. Yes. As shown in Figure 3 below, the Company's reliability metrics (SAIDI,[2] SAIFI,[3] MBI,[4] CAIDI,[5] and CII[6]) were all level over a long period of time, which means that the duration and frequency of outages experienced by customers did not change significantly over time. Maintaining system reliability requires infrastructure improvements and automation as the Company has enabled on its system.

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[2] SAIDI, the System Average Interruption Duration Index, is the average interruption duration in minutes per customer served. It is determined by dividing the sum of all customer interruption durations during a year by the number of customers served. SAIDI = sum of customer interruption durations/total number of customers.

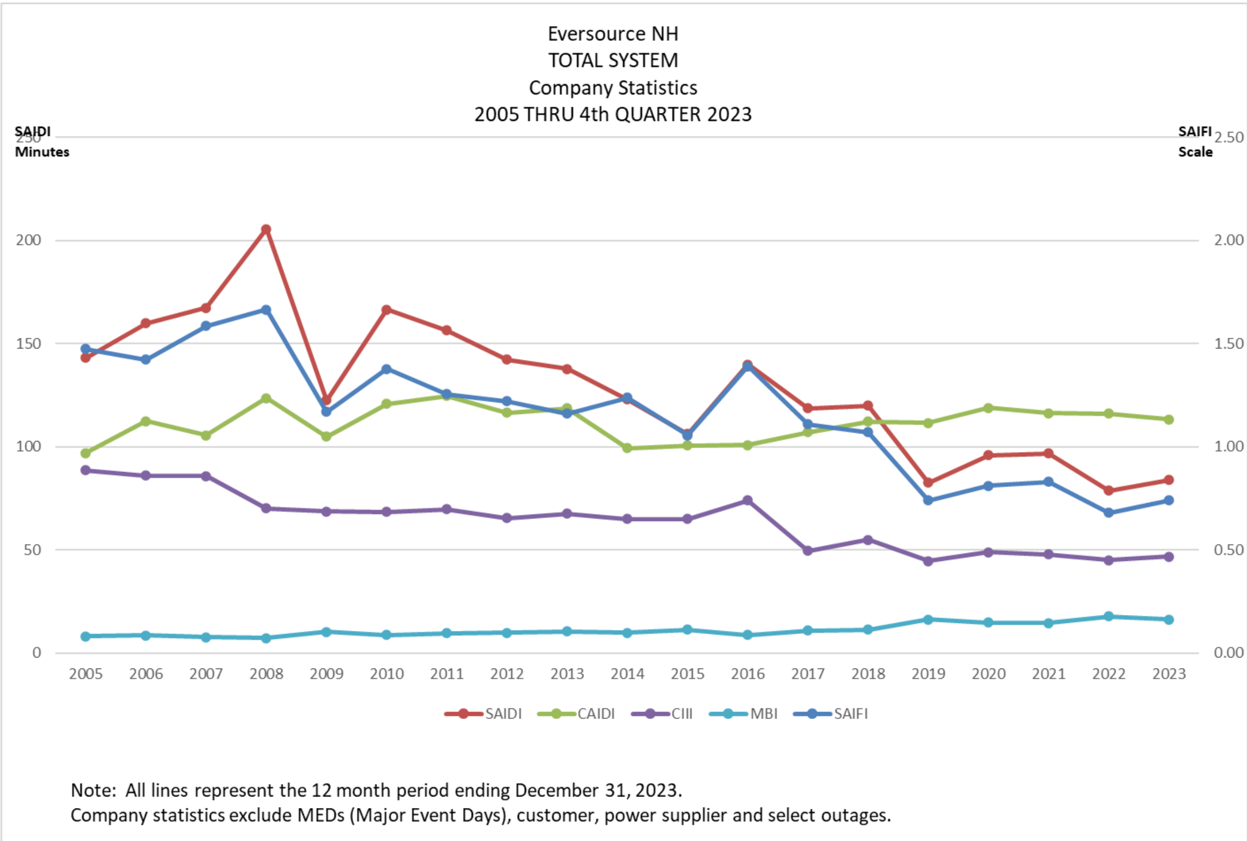
[3] SAIFI, the System Average Interruption Frequency Index, is the average number of times that a system customer is interrupted during a year. It is computed by dividing the total number of customers interrupted in a year by the average number of customers served during the year. A customer interruption is considered to be one interruption to one customer. SAIFI = sum of customer interruptions/total number of customers.

[4] MBI, the Months Between Interruption Index, is the average number of months between when a system customer is interrupted. This metric gives insight into how often the average customer experiences a service outage.

[5] CAIDI, the Customer Average Interruption Duration Index, is the average service restoration time or the average interruption duration for those customers interrupted during a year. It is determined by dividing the sum of all customer interruption durations by the total number of customers interrupted in a year. CAIDI = sum of customer interruption durations/total number of customer interruptions.

[6] CII, the Customers Interrupted per Interruption Index, is the average number of customers without power per interruption. It is determined by dividing the number of customer interruptions in a year by the total number of interruptions.

Figure 3: Reliability Metrics



From 2019 to 2023, the frequency of outages experienced by a typical customer was stable at about 0.74. The system average duration of an interruption ("SAIDI") during the same time period increased slightly from 82.64 minutes to 83.75 minutes and the average number of customers experiencing a system interruption increased slightly from 44.6 to 46.8 customers, representing a two-percent increase. The consistent level of service quality was made possible by the capital investments on the Company's distribution system, as well as vegetation-management work. These investments include pole top distribution automation, circuit ties, replacement of aging equipment as determined by asset condition and maintenance cycles, co-optimized major projects of Transmission and Distribution lines and stations to improve reliability while maximizing efficiency in project execution, station upgrades including automation through technology enhancements (such as fiber optics, microprocessor relays and similar) and relocation of overhead lines from off-road to roadside.

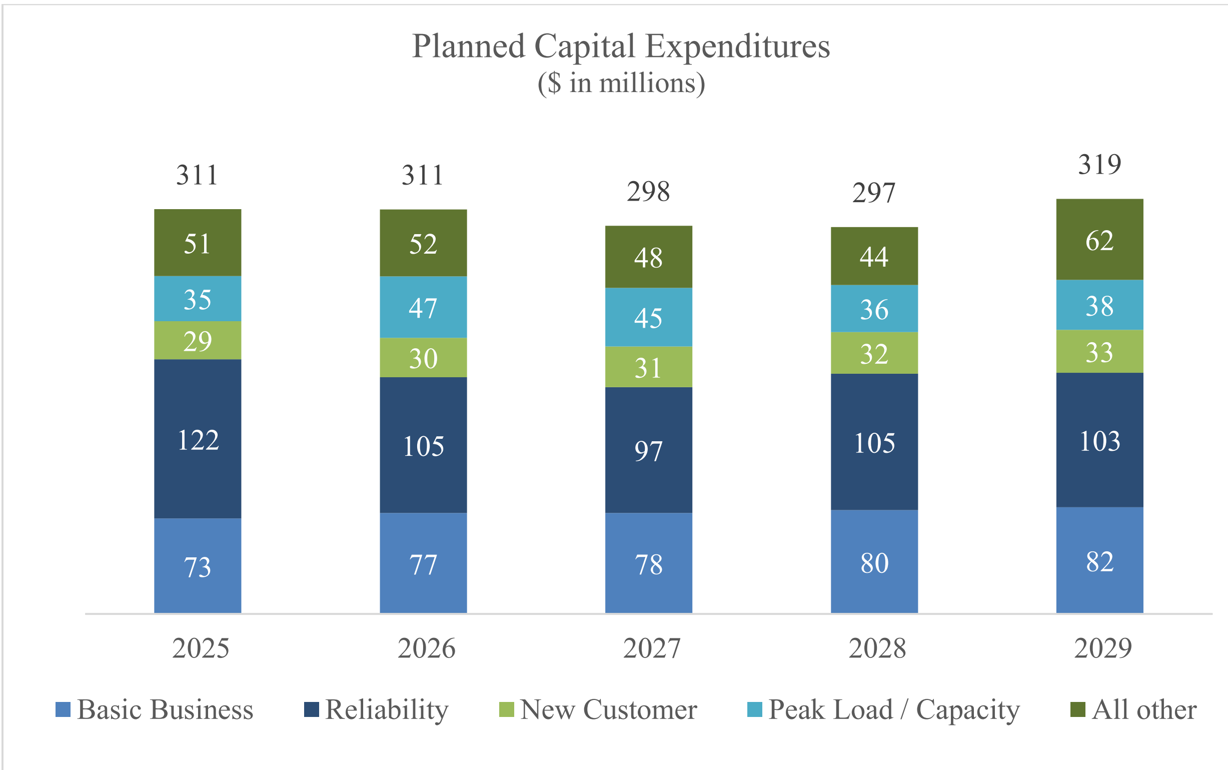
Q. Does the Company anticipate a continuing trend of increasing capital investments over the next five years?

A. Yes. As discussed further in the Company's Distribution Solutions Plan (DSP), Attachment ES-DSP-1, and the System Planning and Solutions testimony, the Company will need to continue a steady ramping of investments on the system to address aging infrastructure and to improve the resiliency of the system in order to protect and enhance system reliability going forward.

As is true elsewhere in Massachusetts and Connecticut, New Hampshire customers have high expectations with respect to the reliability of their electric service and those expectations have grown over time. Every sector of the state's economy depends on electricity as homes and businesses come to rely more and more on technologies that need to be charged. The extent of this dependence is underscored when a significant storm event impacts the region. PSNH fully recognizes the stress and disruption that a power interruption can cause to its customers and continuing capital investment is critical to meeting the challenges of reliability and resiliency for customers.

Although the Company is providing a high level of reliable service as evidenced by the Company's strong SAIDI performance, sustained capital improvements are required to maintain those levels of service and to meet the increasing needs and expectations of the customers served by the Company's electric distribution system. As discussed in the DSP, the Company is faced with large quantities of aging infrastructure that is near or at the end of service life. In addition, the frequency and intensity of storms has increased and is projected to continue to do so, causing significant impacts to the electric distribution system. As outlined in the DSP and discussed below, if the Commission approves the PBR Plan, as proposed, the Company can implement an enhanced resiliency program over the next five years designed to harden the electric distribution system and mitigate the impact of storm-related service disruptions. As shown in Figure 4 below, the Company plans significant capital investments to address system needs in the next five years. The capital plan is primarily driven by substation reliability and obsolescence. The Company, however, is mindful of the potential rate impact for customers and will continue to employ disciplined cost management and continuous efficiency improvements to keep the cost of business operations down.

Figure 4: Five-Year Capital Plan



Q. Does the Company anticipate implementing Advanced Metering Infrastructure ("AMI") in New Hampshire in the next five years?

A. The Company's current five-year capital budget does not contemplate the implementation of AMI in New Hampshire, although the Company continues to evaluate AMI implementation. AMI has the potential to produce significant benefits to the system and to customers. However, there is no doubt that it is a costly investment. AMI is a comprehensive metering and communications system that records customer electricity consumption on an hourly or more frequent basis and transmits measurement over a communication network to a central collection point. To enable the full benefits of AMI, significant infrastructure investment is required beyond simply the metering hardware, including communications infrastructure (to enable remote communication with the meter at each customer's home or business) and back-office information system infrastructure in meter data management, billing and customer information systems.

From 2014-2016, AMR meters were installed throughout New Hampshire. These meters have a useful life of approximately 20 years. Although the Company generally supports the transition to AMI given the additional functionality that could enable new rate designs and other grid modernizations, the optimal timing of deployment depends on a range of variables that factor into the cost-effectiveness determination of that deployment.

In 2023, per the DE 19-057 Settlement Agreement, and in conjunction with DOE and Office of the Consumer Advocate ("OCA"), Eversource hired a consultant to support an AMF Feasibility Assessment in New Hampshire, taking into consideration three scenarios outlined in the DE 19-057 Settlement Agreement. These three scenarios included:

Base Scenario: Eversource transitions from AMR to AMF as soon as possible within the most realistic, near-term timeframe.

Optimized Scenario: Eversource optimizes the Base Scenario to maximize the benefits and minimize the investments of the transition from AMR to AMF.

No AMR Deployed Scenario: This hypothetical scenario assumes that AMR was never deployed and Eversource will transition from manual meter reading to AMF.

From May through September 2023, West Monroe hosted over 50 workshops and meetings with Eversource employees; consulted with over 60 stakeholders across nearly 28 functional areas; and collected over 400 unique data points across 13 infrastructure investment and 10 benefit categories. The Optimized Scenario provided the highest BCR of 0.80 compared to 0.76 for the Base Scenario and 0.78 for the No AMR Deployed Scenario, with the three scenarios ranging from an investment of $394 million to $473 million. The Optimized Scenario does not begin until 2030, while the Base Scenario would begin in 2025. Table 1 provides additional details.

Table 1 - Comparison of Scenarios

	Description	Year 1	Year 20	Deployment Start	Deployment End	Total Investments (NPV 2023$)	Total Benefits (NPV 2023$)	BCR (NPV 2023$)
Base	AMF deployment 2028-2029	2025	2044	2028	2029	$473.2M	$361.2M	0.76
Optimized	AMF deployment 2033-2034	2030	2049	2033	2034	$394.3M	$315.8M	0.80
No AMR Deployed	AMF deployment 2028-2029	2025	2044	2028	2029	$466.4M	$364.9M	0.78

The scenarios outlined in the AMF Feasibility Assessment, developed by the consultant West Monroe, helped provide bookends for the earliest start (2028) and latest start (2033) for AMI meter deployment in NH and presented options for consideration of a path forward in New Hampshire. Decisions to proceed earlier versus later have implications that need to be considered, such as useful meter life. A full business-case analysis would build upon these findings and provide a more comprehensive view with extensive cost estimates for the major investment categories, additional scenarios and expanded sensitivities.

The Company intends to continue to explore the implementation of AMI on the PSNH system as part of its long-term capital program. The Company recognizes the growing interest of various stakeholders, as well as the Commission, in the Company's adoption of AMI. But it is imperative that the Company approach such a prodigious undertaking with the utmost sensitivity for the cost impact for customers and with careful consideration and balancing of state policy objectives, customer needs and interests, and the requirements of the Company's operations, so that the timing of AMI deployment satisfies both customer and grid needs.

IV. OVERVIEW OF THE COMPANY'S RATE FILING

Q. Please describe the elements of the Company's overall filing in this proceeding.

A. First, the Company is requesting a change in base distribution rates to alleviate a revenue deficiency of approximately $182 million. As discussed below, the revenue deficiency is generated primarily as a result of capital investment on the PSNH system over the term 2019-2024, rather than any change in O&M.

Second, the Company is proposing to implement a four-year PBR Plan, inclusive of a capital-support mechanism called a "K-bar," that would adjust rates annually over the next four years in accordance with a revenue-cap formula to be approved by the Commission in this proceeding. The PBR Plan, inclusive of the K-bar, would serve as an alternative approach to recurring base-rate filings followed by annual step adjustments, which the Commission has recognized as appropriate to support needed capital investment between rate cases. The goal of the PBR Plan is to create stronger incentives for cost efficiency, a more direct line of sight into the performance levels customers are paying for, and a level of rate stabilization for customers over an extended time period in order to support capital investment without the "lumpiness" and unpredictability of sequential base-rate filings and associated step adjustments. As explained below, the Company has structured its proposed PBR Plan to encompass risk factors for the Company, as well as allowances to support the operation of the system. If the PBR Plan is approved, the Company is proposing to include certain costs in base rates on a going forward basis, rather than continuing to recover those costs through separate reconciling mechanisms in order to streamline administrative processes and achieve economic efficiency.

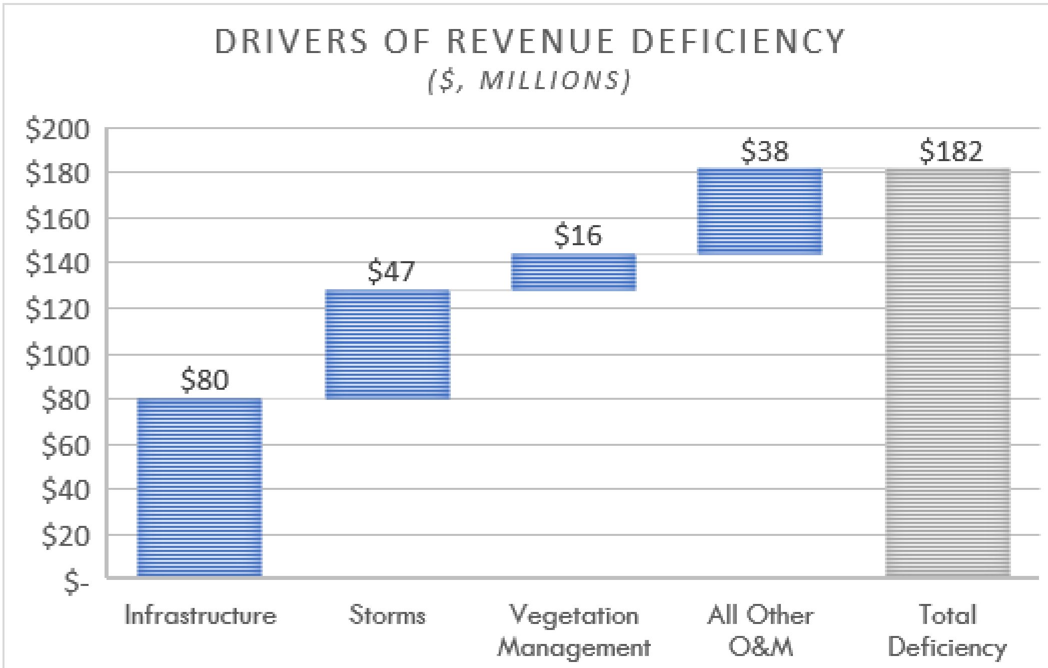
Third, to assure that the Company is continuing to meet its service-quality obligations under a PBR framework, PSNH is proposing to implement enforceable reliability metrics, including corresponding penalties, associated with the Company's SAIDI and MBI performance. In addition, the Company is proposing six additional informational performance metrics in the categories of customer satisfaction, solar interconnection, customer work requests, and active demand response to ensure accountability during the PBR Plan term and provide the Commission, the DOE and key stakeholders insight into the Company's actual performance.

Q. Please describe the Company's request for temporary and permanent rates.

A. The Company's revenue deficiency of approximately $182 million is based on a test year ending December 31, 2023. As such, the Company's current distribution rates are insufficient to recover the cost of providing service to customers inclusive of a fair and reasonable return on the used and useful assets devoted to utility service. Specifically, for the test-year ended December 31, 2023, the Company's earned return on rate base was 6.4 percent, which is below industry standards for a fair and reasonable return -- and 290 basis points lower than the return on rate base of 9.3 percent authorized by the settlement and approved by the Commission in 2020, in Order No. 26,433. Accordingly, the Company now finds it necessary to petition the Commission for review and determination of an increase in base distribution revenues to support utility operations. The Company's filing includes the results of a revenue-requirement calculation; an allocated cost of service study; a marginal cost study; and other testimony and exhibits in support of the Company's proposals in this case.

As explained in the Permanent Rate Revenue Requirement testimony, the $182 million revenue deficiency is primarily associated with increased capital investments, including capital additions expected to be in service by December 31, 2024, along with enterprise IT project costs, vegetation-management costs and non-major storm costs. Figure 5, below, shows the drivers of the revenue deficiency.

Figure 5: Revenue Deficiency Drivers



The Company's proposed temporary rates, proposed for effect on and after August 1, 2024, are outlined in the Temporary Rate Revenue Requirement Analysis. Temporary rates reflect $77 million of the revenue deficiency and are designed to smooth the rate impact for customers associated with the permanent rate increase, while providing a degree of interim rate relief for the Company. The Company's proposed permanent rates reflect the full $182 million revenue deficiency, inclusive of the temporary rate increase.

If the Company's permanent rate proposal is approved without modification, a typical residential customer using 600 kWh/month would experience a total monthly bill impact of 6.57 percent or $8.42 per month as a result of the temporary rate filing, and an incremental 9.62 percent or $13.11 per month as a result of the permanent rate filing. For commercial and industrial ("C&I") customers, the total monthly bill impact averages 5.72 percent for small Rate G C&I customers for the temporary rate filing and an incremental 5.53 percent for the permanent rate filing; averages 2.61 percent for medium Rate GV C&I customers from the temporary rate filing and an incremental 2.88 percent for the permanent rate filing; and, averages 2.03 percent for large Rate LG C&I customers from the temporary rate filing and an incremental 2.67 percent for the permanent rate filing. Individual customer bill impacts will vary from the average impact depending on the amount of usage. Outdoor lighting customers would experience a 12.28 percent increase from the temporary filing and an incremental 10.72 percent for the permanent rate filing.

A summary of the Company's rate request is provided in Table 2, below:

Table 2: Summary of Request for Rate Relief

Filing Component	Amount
Per-book Distribution Revenue Deficiency	($51 million)
Request for Temporary Rate Deficiency:	
Preliminary Storm Cost Amortization	($9 million)
Other Amortizations	($22 million)
Other Revenue Requirement Adjustments	($5 million)
Total Net Deficiency - Temporary Rates	**$77 million**
Full Storm Cost Amortization	($31 million)
Storm Fund Contribution	($7 million)
Pro Forma and Other Revenue Requirement Adjustments	($67 million)
Total Net Deficiency - Permanent Rates	**$182 million**

Q. Does the Company's rate request include proposed step adjustments similar to the 2019 Rate Case?

A. No. For the reasons described below, the Company is proposing a four-year PBR Plan with a capital revenue adjustment (K-bar, as mentioned above), instead of step adjustments to distribution base rates. Below, the Company discusses the operation of the historical step adjustments and the reasons that the step adjustments are not the optimal solution for addressing needed system investment in a manner that provides customers with rate stabilization and service quality.

V. PBR Plan Proposal

A. Overview of PBR Mechanism

Q. Would you please describe the overall structure of the PBR plan?

A. The Company's proposed PBR Plan is designed as a "revenue cap" formula that would be applied to adjust rates on an annual basis over a four-year "stay out" period. The PBR Plan includes the implementation of performance metrics with financial penalties for subpar performance. The components of the PBR Plan are: (1) a revenue cap formula that would adjust the approved revenue requirement from this case on an annual basis to mimic cost trends in the industry; (2) a supplemental capital adjustment (or "K-bar" mechanism) to account for the increasing need for incremental investment on the distribution system; (3) a "stretch factor" or Consumer Dividend that would reduce the annual revenue adjustment by 15 basis points where inflation equals or exceeds two percent; (4) an earnings-sharing mechanism; and (4) an exogenous events provision. Each of these components is described in detail below.

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

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

Where:

$Rev\ Requirement_t$ = the revenue requirement in the current (forecast) period

$Rev\ Requirement_{t-1}$ = the approved revenue requirement in the prior period

I = GDP-PI and must be non-negative

X = Zero

CD = 0.15 when I exceeds 2 percent

Z = an exogenous cost adjustment

K_t = a capital revenue adjustment

ESM = earnings sharing adjustment

Q. Why is the Company proposing a PBR Plan?

A. The Company is proposing a PBR Plan because it is the best way to address the needs of the distribution system, while affording customers a level of rate stability and performance accountability that does not occur through a cycle of base-rate proceedings. A PBR Plan is the optimal ratemaking mechanism to promote long-term cost control, mitigate bill impacts for customers and avoid the need for multiple, sequential base distribution rate proceedings, as would otherwise be needed to address the rising costs of providing electric service on a distribution system experiencing increasing investment requirements, largely due to aging infrastructure and the need to modernize the grid, increased customer expectations, and increased system impacts caused by the frequency and magnitude of major storms. PBR mechanisms in other jurisdictions have proven to be an innovative rate design that is effective in promoting rigorous cost control, while enabling capital investments and serving the interests of customers along the way. The Company's proposed plan is designed based on the lessons learned from other PBR mechanisms and tailored to policies of New Hampshire.

Above all else, annual PBR adjustments will reduce the rate shock experienced by customers. The need for capital investment on the PSNH distribution system is increasing – as the Company raised in its last base-rate proceeding – and the impacts to customers of periodic base-rate proceedings coupled with step adjustments will not achieve the level of rate stabilization and predictability that the PBR Plan can provide. Even with the benefit of annual step adjustments, the cost-of-service increases between rate cases can be significant, as demonstrated by the revenue deficiency that triggered this proceeding. Although more frequent rate cases would alleviate revenue deficiencies temporarily, in the absence of adequate revenue growth due to sales increases or other regulatory support mechanisms between base rate proceedings, the rate increases brought by base rate proceedings will be more and more significant and frequent as a result of the significant cost pressures on the system.

In addition, the proceedings also require significant administrative resources from the Company, the Commission, the DOE, OCA and other stakeholders. Through the balanced PBR Plan, the Commission can approve reasonable rate adjustments that provide some necessary revenue support for the Company between base-rate proceedings, avoid rate shock to customers, maintain accountability for the Company to provide safe and reliable service at a reasonable cost, and ensure that costs are reasonably and prudently incurred, all with much greater administrative ease and efficiency.

As compared to capital cost recovery mechanisms, such as the step adjustments previously approved by the Commission, PBR can provide strong incentives to the electric utility to control costs and promote performance that furthers safe and reliable service at the lowest cost. Cost control, in particular, is a critical objective in an environment where electric utilities are facing financial challenges resulting from the increased costs of energy infrastructure, which are not supported by commensurate increases in customer sales and revenues that would naturally support the increasing costs, generally due to increased distributed energy resource ("DER") deployment, successful energy efficiency efforts, and increasing customer awareness and actions to conserve energy consumption.

The PBR construct challenges the Company to find better, more innovative ways to achieve cost reductions while still providing customers with safe and reliable service, which benefits the overall system. The Company's proposed PBR Plan includes performance metrics that provide financial consequences to ensure the Company operates the system at a consistently high service-quality level, while achieving cost efficiencies. Customers also benefit from rate stability associated with smaller sequential changes occurring annually, rather than more significant bill impacts occurring every couple to few years. Further, since PBR produces annual rate changes that are tailored to reflect the cost trends of the utility over time, the annual rate changes under PBR present a more natural, predictable glide path of rate changes over time, rather than larger increases coming as a result of base rate cases every two to three years. In addition, because PBR comes with a commitment by Eversource to "stay-out" of a rate case for at least four years, a commitment that is not possible with step adjustments in their current form, the Company has greater incentives under PBR to pursue cost efficiencies in the short and long run, which produce customer benefits from rate increases that are lower than might otherwise occur.

Q. Is the PBR plan structured as a "cost recovery" mechanism?

A. No. The PBR plan is not a cost-recovery mechanism and the annual revenue adjustments produced by the PBR formula are not intended to track the company-specific cost of service or any element therein. Rather, the annual revenue adjustments provided each year are intended to track an industry cost trend, providing a revenue "allowance" to the Company to support utility operations while the stay-out term pushes the utility to achieve cost efficiencies in order to maintain financial integrity within the parameters of the annual revenue adjustment. In that way, PBR creates broad-based incentives for cost control because it applies across the utility operation supporting both capital investment and O&M costs and because the PBR formula is not linked to the Company's actual costs but rather based upon the electric-industry's expected productivity. Rather than representing a cost-tracking or capital reimbursement mechanism, PBR is designed to provide a level of incremental revenue to support electric operations, without ascribing that revenue to any particular cost item in the cost of service.

This is a critical difference between PBR and a cost-recovery mechanism because PBR allows the Company to allocate financial resources optimally to support business functions, programs and projects that are necessary to provide safe and reliable service to customers on an integrated basis. At the same time, if the Company is able to find areas where it can cut expenses, or slow increases in costs through management initiatives, organizational changes, systems implementation, or any other means, it retains the benefit of those cost reductions until the next rate case, at which time all of the cost savings embedded in operations are transferred to customers in the cost of service for the next base-rate period. In some cases, it costs money in the short term to implement long-term cost reduction initiatives. During a PBR term, a company may be more willing to bear the expense of a cost-cutting initiative knowing the company will retain savings over a multi-year period to offset the expense.

In sum, implementation of a PBR plan is designed to enable a utility to avoid frequent base rate cases while creating a broader operational directive that also fosters a greater opportunity to achieve cost savings in the process of fulfilling the Company's charge of safe and reliable electric service for all customers.

Q. Has the Company structured the proposed PBR Plan to incorporate both allowances and risks for the Company and discrete benefits for customers?

A. Yes. The Company is approaching this case with the knowledge of certain key prerequisites. First, the PSNH distribution system needs an increasing level of investment due to its age and condition and the need to modernize to meet today's economic, societal and environmental requirements and obligations. As a responsible operator (and steward) of the distribution system, the Company needs to make this investment to protect the interests of customers and the State of New Hampshire over the long term. Second, the increasing cost of electric service has implications for customers in terms of affordability and rate stability, particularly where New Hampshire lacks the vibrant economic centers that are encompassed within jurisdictions like Massachusetts and Connecticut, helping to offset the costs of service to smaller customers. Third, as the largest electric operator in New Hampshire, the Company recognizes that a regulatory plan that provides the opportunity to increase transparency, reduced administrative burden and balance among the regulatory stakeholders is a mandatory ingredient. Lastly, the Company recognizes that any long-term regulatory plan will need to incorporate both allowances and risks to achieve the balanced outcome that regulatory stakeholders will demand from a PBR plan.

With these prerequisites in mind, the Company has structured the proposed PBR Plan to provide the Company with a discretely calculated revenue "allowance," comprised of a base revenue adjustment and a supplemental capital adjustment, described elsewhere in this testimony. Conversely, the Company has structured the PBR Plan to incorporate four primary areas of risk. These areas of risk are:

- <u>Commitment to a Four-Year Stay-Out Term</u>. As discussed below, the Company is proposing that implementation of the PBR Plan would require a commitment from the Company to abstain from filing a new petition for base rates that would take effect before August 1, 2029. Over this term, the Company would be eligible for three revenue adjustments taking effect on August 1, 2026, August 1, 2027 and August 1, 2028, and would be limited to those revenue allowances over the four-year term with the exception of a qualifying exogenous event. To intensify the "stretch" impetus of the stay out for the benefit of customers, the Company is proposing an asymmetrical earnings sharing mechanism that would share actual earnings above the authorized return with customers, but would not allow the Company to recover additional revenues from customers below the authorized return.

- <u>Risk of Capital Requirements Exceeding the Capital Allowance</u>. Below, the Company describes the capital allowances that would be provided to the Company under the PBR Plan. The Company is proposing three separate constraints on the magnitude of the capital allowance. These constraints are: (1) the supplemental capital mechanism (K-bar) is specifically designed to provide recovery of capital additions, less than the actual amount of rate base additions that are anticipated to occur over the PBR Term so that there is an inherent efficiency incentive; (2) use of a three-year historical average to determine the threshold quantity of capital allowance enabled by the K-Bar rather than using current amounts of capital additions for the allowance; and (3) a cap on variation from that allowance of 10 percent greater than the Company's forecasted capital expenditures as of today. To the extent that the Company's capital requirements are greater than this allowance in any given year, the Company would have to wait to propose recovery of those amounts in the next rate case. In addition, the Company bears the risk that capital costs will exceed the capital allowance due to actual construction costs rising higher than GDP-PI on projects that are currently contemplated in the Company's plan, which is prone to occur (and has occurred over the past few years).

- Risk of Declining or Flat Revenues. Below, the Company discusses its proposal to forego the implementation of revenue decoupling and take the risk of revenue fluctuations up or down over the term of the PBR Plan. As part of this proposal, the Company is proposing to eliminate the recovery of lost base revenues associated with energy efficiency and net metering, except in circumstances where the level of net metering reaches a significance threshold that would undermine the long-term balance and stability of the PBR Plan.

- Risk of Financial Penalties for Subpar Performance. With approval of the proposed PBR plan, the Company proposes to implement numerous metrics within certain performance categories that will provide transparency in relation to the Company's performance, allowing the Department and other stakeholders to gauge the Company's progress on its PBR plan commitments. The Company's proposed service-quality metrics include baselines that, if not achieved, would result in penalties assessed against the Company and distributed to customers as a credit in the subsequent year.

Q. Is the Company proposing to eliminate certain reconciling mechanisms as part of its PBR proposal, and instead to incorporate those costs into base distribution rates as part of the PBR Plan.

A. Yes. As discussed below, one of the objectives of the Company's PBR plan is to provide increased administrative efficiencies that will reduce costs and provide greater benefits to customers, the Commission and other regulatory stakeholders. Under traditional ratemaking, reconciling mechanisms provide on-going revenue support to the Company in between rate cases for specific and targeted cost elements. If the Company's proposed PBR Plan is approved as filed, the Company will receive additional revenue support through annual PBR adjustments that will support the cost trajectory of certain costs that are currently tracked and recovered on a reconciling basis in distinct rate components. Although it is certainly possible for reconciling mechanisms to coexist in a PBR framework without impairing the efficiency incentives inherent in the PBR Plan, the Company is positioned to eliminate certain reconciling mechanisms that exist today, and instead reflect those costs in base rates, should the PBR Plan be approved. The annual rate adjustments that would come under the PBR framework proposed by the Company are expected to be sufficient for the Company to sustain itself during the four-year PBR Plan and to cover the cost changes associated with the existing reconciling mechanisms, thereby reducing the administrative burden associated with those mechanisms.

Specifically, the Company proposes to recover in base rates, rather than through reconciling mechanisms, costs associated with property taxes, vegetation management, long-term debt for storm costs, rate case expense and the Pole Plant Adjustment Mechanism. The Company is also proposing to eliminate lost base revenues associated with energy efficiency and net metering. The Permanent Rate Revenue Requirement Analysis testimony provides more details on the Company's proposal for consolidation of these costs into base rates where the PBR Plan is approved.

However, if the Commission rejects the Company's proposed PBR Plan, the Company will need to maintain all of these existing reconciling mechanisms without modification because there will not be adequate revenue support provided through step adjustments for the Company to absorb the increasing costs associated with these elements while also funding core system requirements for capital and expense.

B. Revenue Cap Formula (I-X)

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

A. The PBR revenue cap formula is derived through economic analysis of utility cost trends as indicated by measures of inflation, input prices and total factor productivity. The specific revenue-cap formula proposed by the Company is discussed in the testimony of Mark Kolesar and Dr. Augustin Ros. Mr. Kolesar and Dr. Ros have performed in-depth economic research and analysis supporting the Company's proposed revenue-cap formula and their testimony details the methodological underpinnings for the revenue-cap formula.

The economic analysis yields a revenue-cap formula with an annual "I-X" adjustment, where "I" represents a measure of economy-wide output inflation, in this case the Gross Domestic Product – Price Index ("GDP-PI"), as measured by the U.S. Commerce Department, and "X" is a measure of expected industry-wide productivity.

Mr. Kolesar and Dr. Ros explain that the allowed rate of change for the revenue-cap index is equal to the rate of general price inflation in the aggregate economy less an adjustment factor (the X factor). The X factor consists of the differential in expected productivity growth between the electric-distribution industry and the overall economy and the differential in expected input price growth between the overall economy and the electric-distribution industry. Although X is typically determined by a productivity study based on historical information, X is forward looking as it is based on what differentials are expected to occur going forward. The analysis conducted by Dr. Ros indicates an "X" factor of *negative* -1.42 percent, implying that the annual revenue adjustment should be Inflation *plus* 1.42 percent.

Q. Why is the X factor negative?

A. As explained in the testimonies and exhibits of Company Witnesses Kolesar and Ros, the X-factor is designed based on statistical analysis to reflect the average cost and productivity trends of the electric distribution industry of relative to the economy cost and productivity trends and the general inflation. Combined with the "I" factor, "I – X" represents the expected unit cost performance of an average performing company in the industry. The "negative" X-factor reflects the fact that electric utilities are currently in a situation where their inputs are increasing, but the units of outputs are declining, which is not the case for many other businesses in the general economy. This makes sense given that the electric distribution business is a highly capital-intensive business, notwithstanding the fact that outputs (at least in the form of kWh) are flat or declining.

Q. Is the Company requesting that the Commission adopt the negative X-factor value derived through the economic analysis performed by Dr. Ros?

A. No, the Company is not proposing the negative X factor as the basis for the annual revenue adjustment. Although the expert analysis and best practices for PBR mechanisms support inclusion of the negative X-factor specified by Dr. Ros, the Company proposes to voluntarily set the X-factor to zero for the proposed PBR term. The Company's experience is that the negative X factor has the connotation of "inefficiency," i.e., that the negative X factor is perceived as rewarding the utility for being less efficient than other businesses in the overall economy, although this is not the case. Other businesses in the economy do not have increasing capital requirements for infrastructure needs, despite declining outputs and this is what is reflected in the negative X factor. The Company has learned that the reality is that regulators are reluctant to accept the concept that a negative X-factor is necessary for the PBR framework to work given the economics of the utility business. In addition, the Company's experience in Massachusetts is that the regulators wanted a tighter connection between capital funding and capital projects, which is possible through the use of the K-bar construct rather than reliance on a negative X factor.

If a PBR mechanism is not properly calibrated -- either because cast-off rates are established too high or too low,[7] or because the X-factor is too high or too low, the incentives promised by the PBR framework will lose their efficacy. Where the cast-off rates or X-factor calibration are off, the utility will not be able to keep its commitment to stay out of a rate case or, alternatively, the "stretch" incentives will be eliminated, muting the cost-control benefit that is intended to produce lower rates for customers than would otherwise occur over time.

Acknowledging that a negative X-factor may be unpalatable for the Commission, the Company is proposing to set the X-factor to zero and to substitute the K-bar mechanism to create a tighter link to capital expenditures. Setting the X-factor to zero provides customers with a benefit akin to an additional consumer dividend and will strongly encourage the

[7] "Cast-off rates" refer to the approved base distribution rates following a rate case to be the starting point for any PBR plan adjustments.

Company to identify additional cost control opportunities. As described below, the K-bar mechanism has been adopted in other jurisdictions as a way to support growing capital investment needs on the system, while maintaining the cost control incentives inherent in a PBR framework.

When taken together and applied to an appropriately constructed cast-off rate, the Company's proposed PBR formula is designed to give the Company sufficient, but not more than sufficient, revenue to provide the Company with an opportunity to cover its operating expenses and the opportunity (but not a guarantee) to earn its authorized ROE in a given rate year. The Company's PBR Plan, including the zero X factor, K-bar capital mechanism and the elimination of certain reconciling mechanisms and lost base revenue is a superior ratemaking framework for customers, providing revenue support, administrative efficiency, rate stability and service quality in the form of safe and reliable electric service.

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

A. The formula for calculating the PBR adjusted rates is described above. To derive the annual PBR adjustment, the Company would use GDP-PI information published by the end of January in the Survey of Current Business, a publication of the U.S. Commerce Department, Bureau of Economic Analysis.[8] The inflation index would be adjusted annually and would be calculated as the percentage change between the current year's GDP-PI and the prior year's GDP-PI. For each year, the GDP-PI would be calculated as

[8] The Bureau of Economic Analysis' first release is issued by the end of January for the Q4 data from the prior year, which are finalized in the February/March timeframe each year.

the average annual percentage change of the most recent four quarterly measures of the GDP-PI as of the fourth quarter of the year and shall not exceed 5 percent or fall below zero percent.

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

A. Yes. Although negative inflation is unlikely, in the event that inflation is negative in a single year, the Company proposes to set the "I" to zero. Because the purpose of the PBR plan is to provide revenue support and the Company is foregoing the X factor within the PBR formula while also making significant commitments to capital improvements and performance metrics, it is necessary for the Commission to establish a zero percent inflation floor. Otherwise, the Company would be penalized in relation to the revenue support contrary to that which the PBR mechanism is supposed to provide, and that would otherwise be provided under traditional cost of service ratemaking without the same performance commitments.

C. Capital Revenue Formula (K-bar)

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

A. The Company proposes to use the "K-bar" approach to provide supplemental revenue to support capital investment over and above the "I-X" revenue cap formula. The K-bar formula applies to all capital investments and is based on a rolling three-year historical average of capital additions, adjusted by the I-X formula, where X is set to zero. Attachment ES-DPH-1 provides an overview of the K-bar formula and the calculation to be included in the annual Performance Based Ratemaking Adjustment ("PBRA") filings, as described further below.

The K-bar is based on actual capital expenditures without involving the administrative burden of an annual capital tracker or step adjustment process. Instead, K-bar relies on computations of the revenue requirement associated with rate base based on historical actual plant additions, as adjusted to rate year levels. The K-bar incorporates an inherent cap on recovery because it is calculated on the basis of recent average plant activity, which means that the mechanism is inherently limited in any given year by the degree to which actual plant in service differs from the average utilized in the K-bar computation, as well as an explicit cap on the formula by application of the ten percent cap, as calculated in Attachment ES-DPH-2, and described further below.

Specifically, the K-bar formula establishes a level of eligible capital recovery based on a rolling historical three-year average of capital additions that went into service as of December 31st of the year prior to the rate effective date. In this case, the Company is proposing that the K-bar formula that would apply to the PBR rate change effective August 1, 2026, and would be based on the average of plant additions in effect for the three years ending December 31, 2025, adjusted to the rate year level, as described below. Under this approach, the I-X formula escalates the value of historical average capital additions to rate year levels to establish a proxy of the cost of capital additions in the rate year, based on historical levels of plant additions. Capital additions include plant additions, cost of removal and retirements. Recoverable capital expenditures are obtained from the differential between the utility's escalated historical capital needs and what the Company will actually collect under the I-X formula for these types of capital additions. Because this formula is based on a rolling three-year historical average of plant additions, it is not based on actual plant additions in the rate year, as is the case with a typical capital cost recovery or a properly constructed step adjustment. In this way, particularly in times of increasing capital expenditures on the system, the level of revenue support provided by application of the I-X-factor and K-bar formula incorporates a level of regulatory lag, where the revenue support lags the costs associated with expenditures in a given year. This lag helps to retain better cost control incentives as an element of PBR, while also producing sufficient revenue support for the utility to fund ongoing capital investment needs and the opportunity to earn sufficient returns to support that level of capital, provided the Company is able to manage the growth of capital expenditures to fit under the umbrella of revenues provided by the formula.

The rolling-average K-bar provides customers protection from annual rate increases that do not reflect recent capital investment levels and mitigates the magnitude of rate adjustments. To further protect customers from substantial rate increases in the event the Company is required to make significant capital investments in a single year, the Company also proposes to implement a limit on the amount of capital improvements that may be included in the annual K-bar adjustment. The Company proposes to cap the annual capital costs eligible for inclusion in the rolling-average of historical capital additions. The cap will be set at ten percent above the forecasted annual capital spending included in the Company's five-year capital budget provided in Exhibit ES-DPH-2 and in Figure 4 above. There are inherent challenges in forecasting capital spending and therefore the Company proposes a limited level of flexibility from the Company's forecasted capital budget in setting the annual cap for the K-bar.

All capital investments would remain subject to a prudence review and potential disallowance from rate base as part of the Company's next base-rate proceeding, including any capital above the K-bar cap. The Company will produce all documentation supporting capital investments in its initial filing for that proceeding.

Q. Please describe how the PBR and K-bar adjustment will be calculated each year to adjust base distribution rates.

A. Attachment ES-DPH-1 provides an illustrative analysis of the annual PBR adjustments, inclusive of the K-bar adjustment, to be included in the annual PBRA filings for each year of the PBR term, beginning with the first PBRA adjustment on August 1, 2026. Page 1 summarizes the calculations that are presented on pages 2 through 10 to provide the target base distribution revenues for each year of the PBR plan operation, using the capital forecast to be in-service each year during the term. The results of the PBR Plan estimate base distribution revenue changes of $52 million, $29 million and $32 million on August 1, 2026, August 1, 2027, and August 1, 2028, respectively.

In its calculations, the Company first determined the adjustment produced by the I-X revenue cap. The starting point for PBR adjustment is the base distribution revenue requirement as proposed in this proceeding on page 1, lines 1 through 3, of Attachment ES-DPH-1, which would be updated to reflect the approved base distribution revenue requirement in the Commission's final decision in this proceeding. The base distribution revenue requirement, for purposes of calculating an annual adjustment, excludes other revenues as well as the annual contribution to the storm reserve and any unrecovered storm costs being amortized in base rates, as shown on Attachment ES-DPH-1, page 1, lines 4 and 5. The items listed are not included in the distribution revenue requirement, which is subject to change annually for inflation by the I-X formula. By excluding these amounts from the calculation of the PBR increase, these amounts will stay at the level established in the last rate case, rather than adjusting annually according to the I-X formula. The resulting base revenue requirement on page 1, line 6, is the starting point for the annual adjustment on August 1, 2026. Annually thereafter, the Company relies on the base revenue requirement as adjusted annually by the I-X formula on page 1, line 7, to apply the annual percentage change on page 1, line 9. The annual PBR adjustment based on the I-X formula is shown on page 1, line 10 and added to the base revenue requirement from the prior year to produce the target base distribution revenue requirement for the current year, as adjusted by the I-X formula as shown on page 1, line 12. The analysis shows that the annual PBR adjustments are about $10 million per year.

Next, the Company determined the K-bar adjustment, which is intended to provide supplemental revenue to support capital additions over and above the I-X revenue-cap formula. The calculation of the K-bar adjustment is summarized on pages 2 and 3.

- **Step 1** for the K-bar adjustment is to identify the capital-related base distribution revenue requirement as proposed in this proceeding on page 1, lines 1 through 3 and page 3, lines 2 through 5. The base capital revenue requirement reflects the depreciation expense, pre-tax return on rate base and property tax expense that would be updated to reflect the approved base distribution revenue requirement in the Commission's final order in this proceeding.

- **Step 2** is to calculate the I-X percentage change relative to the 2024 summarized on page 2, line 7 and detailed on page 3, lines 9 and 10.

- **Step 3** then escalates the base capital revenue requirement by the I-X formula summarized on page 2, line 8 and detailed on page 3, lines 13 through 15.

- **Step 4** calculates the K-bar revenue requirement. The K-bar revenue requirement summarized on page 2, line 10 is determined using the historical average of plant additions, cost of removal and retirements and escalates to the current dollars using the I-X formula as the basis for calculating the rate base activity. The Company calculated the K-Bar revenue requirement using the composite depreciation rate, pre-tax return on rate base, and property tax expense rate as approved in the Company's most recent base distribution rate case, Docket No. DE 19-057. For purpose of this analysis, the Company has reflected the proposed rates in this proceeding. Page 3, lines 20 through 23, present the K-Bar rate base activity beginning in 2025 and continuing through July 31, 2026, and for each rate year of the PBR plan, beginning August 1, 2026, August 1, 2027, and August 1, 2028, including plant additions, cost of removal, retirements and accumulated deferred income taxes. These amounts represent a historical three-year average of actual plant activity in each year, escalated to current year dollars using the I – X formula, as shown on page 8.[9] Page 3, lines 47 through 50 calculate depreciation expense, return on rate base and income tax, and property tax expense associated with the K-Bar rate base as calculated on page 3, lines 27 through 44. The sum of these capital costs on page 3, Line 50 is the K-Bar Revenue Requirement.

- **<u>Step 5</u>**: The resulting K-bar revenue requirements in Step 4 on page 3, line 54 are then compared to the capital recovery supported by the operation of the base I-X formula on page 3, line 53 to determine the incremental capital support required, to yield the K-bar adjustment. The K-bar adjustments are estimated at $42 million, $19 million, and $21 million for August 1, 2026, August 1, 2027 and August 1, 2028, respectively.

Q. Please describe how the cap associated with capital additions eligible for inclusion in the K-bar will be calculated.

A. The K-bar serves as a natural limit on the level of revenues available to the Company to support ongoing capital investments. This limit is essential to preserving the natural incentives inherent in a PBR framework, because the K-Bar calculation naturally

[9] The inputs for these calculations are presented on pages 4, 5, 6, and 7 for plant additions, cost of removal, retirements and accumulated deferred income taxes, respectively.

incorporates the concept of "regulatory lag," providing additional revenue support to the utility to run the business, without a need for "dollar for dollar" recovery of costs associated with either capital or O&M. The three-year rolling historical average creates a limitation in that the K-Bar mechanism does not immediately adjust to increasing spending, as would a properly designed step adjustment or capital tracker. Instead, the K-bar allows only one-third of the most recent year's increased capital investment to enter into customer rates, thereby adjusting to increasing capital investment requirements on a slow and steady basis as higher spending years are incorporated into the average. In addition to this measured roll-in, the Company is proposing to incorporate an additional protection in the form of an annual cap on the K-bar adjustment.

Attachment ES-DPH-2 provides the calculation for the K-bar capital allowance. There is a limit to the amount of capital improvements that may be included in the annual K-Bar adjustment, imposing an annual capital expenditure constraint of up to ten percent from the annual capital expenditure forecasted in this docket, referred to as the forecasted budget. Beginning with the annual PBR adjustment effective August 1, 2026, the Company's actual capital additions for the prior year are allowed for inclusion in the calculation of the K-Bar adjustment capital costs to the extent that the actual capital additions do not exceed the forecasted budget by more than ten percent, with no prudence review applicable at that time. To the extent that the cumulative actual capital costs in-service through the prior year, in aggregate, exceeds the forecasted budget through the prior year by more than ten percent, then the K-Bar allowance is capped at the ten-percent variance from the forecasted budget, by excluding the variance from the K-Bar adjustment.

Page 1, lines 10 through 35 include the Company's forecasted budget for each year from 2025 through 2027 by investment category.[10] The cumulative capital spending in each year is escalated by ten percent to determine the total capital allowed to be reflected in the K-Bar adjustment for each year on line 41. This is then compared to the cumulative actual capital investments in service, including cost of removal, for each year. If the cumulative capital investment in-service on page 1, line 45 exceeds the total capital allowed for K-bar on page 1, line 41 in any given year, the Company will be ineligible to include the investments above the cap on page 1, line 49 in the K-bar adjustment.

Q. Is the Company proposing any exceptions to the K-Bar cap described above?

A. Yes, on a very limited basis. From time to time, and as described in the DSP, the Company encounters the opportunity to pursue beneficial reliability enhancements through co-optimization of customer-driven investments. Periodically, the Company must make significant infrastructure investments to accommodate a major, large new or expanded customer load. These major customer projects may include a significant increase in load at a regional airport or a very large redevelopment project, for example. In these circumstances, the customer contributes to the cost of the project through a contribution in aid of construction (CIAC) charge. However, these projects may also provide an

[10] Unless extended, the last year of capital additions to be reflected in the K-bar adjustment for the four-year PBR Plan term is calendar year 2027.

opportunity for limited incremental investments to address broader reliability and resiliency opportunities that benefit the broader customer base. Co-optimized opportunities to build capacity and additional feeders significantly improve reliability for all customers by: (1) adding more operational flexibility to supply demand during emergencies; (2) improving feeder design such that there are less customers to be in each protection zone; and (3) creating more circuit ties to safely reconfigure the system after failures. The additional capacity and infrastructure also increase DER hosting capacity, allowing higher penetration of clean energy resources into the system.

Although these potential co-optimized reliability enhancement opportunities are limited and infrequent -- in certain instances – the projects are significant. It is naturally challenging to project the timing and costs of these projects since they are largely dependent on customer needs and requests. Accordingly, given the uncertainty as to the timing and scale of these potential investments, if the projects arise and have the effect of causing the Company to exceed the K-bar cap in a given year, then the Company proposes that these projects be excluded from the annual K-bar cap, so long as the Company demonstrates that the amount above the cap would not exist but for the inclusion of a significant project allowing for the co-optimization of customer-driven investments.

By excluding these limited co-optimized reliability projects from the K-bar cap, the Company will be able to better manage its planned capital portfolio and more readily pursue the less predictable co-optimization opportunities stemming from major customer projects. The Company proposes to notify the Commission of any known co-optimized reliability projects that the Company intends to undertake as part of its annual PBR adjustment filings, so that it has a line-of-sight into the potential for this occurrence during the course of the PBR plan.

Q. Has the Company identified any incremental investments that could be undertaken during the term of the PBR Plan, other than the core capital investments already contemplated by the Company?

A. Yes. With the Commission's approval, the Company could implement certain grid enhancements that are not currently contemplated in the Company's five-year expenditure forecast. These incremental grid enhancements are outlined in the DSP, as follows: (1) enhanced resiliency programs; (2) a set of grid modernization investments, including volt/var optimization (VVO); and (3) Company-owned solar. These grid enhancement proposals will provide customers with increased benefits of modern grid technologies. If the Commission views these incremental investments as warranted and appropriate, the Company is willing to support these measures without a reconciling mechanism in order to provide enhanced benefits to customers, while maintaining the burden to prove the prudency of such investments during future distribution rate review proceedings, where the Company's PBR Plan is approved with an appropriate K-bar mechanism. This would create an inherent stretch factor for the Company in terms of the amount of the K-bar allowance generated by the formula, which would be the same with or without these investments. However, calculation of the 10% variance cap would need to exclude the costs of these programs given that these projects are not currently reflected in the Company's long range capital budget.

Q. Is the Company proposing any reporting requirement for its PBR Plan to provide transparency on capital expenditures enabled by the K-bar adjustment?

A. Yes. As part of its annual PBR filings, the Company will file a forecast of the capital projects planned to go into service in the rate year, and the associated costs of those projects, for informational purposes. In addition, the Company could file the actual distribution plant additions reported on the FERC Form 1 for the prior calendar year that shall be the basis of the K-Bar adjustment. For example, in its 2026 annual PBR filing, the Company would file its forecasted 2026 planned capital projects expected to be in service. Then, in its 2027 annual PBR docket, the Company would make an informational filing of its actual 2026 capital additions placed in service, as reported in the FERC Form 1 included in its annual PBRA filing to be submitted no later than May 15th of each year.

D. Stretch Factor (Consumer Dividend)

Q. Please describe the proposed "stretch factor".

A. The "stretch factor" is intended to share expected gains in cost performance under the PBR plan with customers. The Company recognizes this principle and agrees that customers should benefit from the implementation of the PBR plan. Specifically, the Company is proposing to implement a consumer dividend of 15 basis points where inflation exceeds two percent. The consumer dividend decreases the annual PBRA percentage increase applied each year. This stretch factor is proposed by the Company to ensure that customers benefit from the achievement of cost efficiencies over the PBR term.

As discussed above, customers are also receiving an additional benefit from setting the X-factor to zero, which effectively provides customers with an implicit consumer dividend because the Company would absorb the negative X-Factor offset calculated by Dr. Ros on the non-capital-related components of the Company's cost of service.

Q. What is the basis for the Company's Consumer Dividend of 15 basis points when inflation exceeds two percent?

A. In preparing the proposed PBR plan, the Company consulted with Dr. Ros as to the theory of the consumer dividend and the possible methods for determining an appropriate value given the Company's specific circumstances. Dr. Ros advised the Company that while the ultimate determination of a consumer dividend value is largely subjective, quantitative data on the Company's cost performance can help inform the Commission on appropriate consumer dividend values in light of the Company's current circumstances, as well as other elements of the PBR proposal that may provide benefits to customers such as the adoption of a zero X factor, the inclusion of an earnings sharing mechanism in the PBR plan, and the potential for customers to receive substantial benefits at the termination of the plan when cost gains made under PBR are passed through into rebased distribution base rates.

In this case, the Company is proposing a 15 basis-point Consumer Dividend factor to demonstrate the Company's commitment to provide customers with an explicit, tangible benefit stemming from operating-cost control. Under circumstances where inflation is greater than two percent, the Company's operating costs will be increasing at a fairly substantial pace, and the 15 basis-point consumer dividend will force the Company to work hard to find ways to suppress cost increases to the direct benefit of customers in the next rate case.

This is appropriate because, as describe in the testimony of Dr. Ros, the empirical evidence underlying PBR suggests that the PBR adjustment should produce annual revenue increases for O&M equal to inflation *plus* 1.42 percent (where the PBR formula is I-X, and X is equal to -1.42 percent). However, as described above, the Company is proposing to implement an X factor of 0, rather than -1.42 percent, which is mathematically akin to including a consumer dividend of -1.42 percent on the O&M portion of the PBR adjustment.[11] In other words, the Company is already going to be challenged to find significant savings opportunities on an annual basis under the PBR plan proposed herein by limiting the X factor to 0. Applying an additional consumer dividend at lower inflation levels above and beyond that which is inherent in the Company's proposal could tip the scales to make the revenue support too restrictive and undermine the incentives of the PBR plan and potentially make it impossible for the Company to hold to its commitment to stay out of a rate case for four years.

[11] The capital portion of the PBR adjustment is encompassed by the K-bar calculation and is impacted differently than the O&M portion, as it relates to the application of a X Factor equal to 0.

E. Earning Sharing Mechanism

Q. Please describe the Company's proposal for earnings sharing with customers during the term of the PBR Plan.

A. The Company views the implementation of an earnings-sharing mechanism to be a necessary guardrail for customers within the context of the PBR mechanism. Under economic theory, the implementation of an earning-sharing mechanism is viewed as counteracting the cost-efficiency incentives inherent within a performance plan by sharing the cost savings with customers rather than allowing the Company to retain the "fruits of its labor," as economic theory would suggest. However, as part of the Company's commitment to a PBR Plan that provides benefits to customers, the Company is proposing an earning-sharing mechanism that would trigger sharing on a 75 percent (customer), 25 percent (Company) basis where the computed distribution return on equity ("ROE") exceeds 25 basis points above the ROE authorized in this proceeding.

The calculation for the earning sharing mechanism would exclude Commission-approved incentive payments, such as energy efficiency incentives, and would also exclude any service-quality performance metric penalties, as well as any amounts recognized in the relevant period resulting from regulatory or court settlements or sums arising from decisions related to prior periods (if any). The calculation for earnings sharing would also be dependent on the distribution company's earnings exclusive of transmission-related impacts. For any year in which the return on equity is above 25 basis points, the percentage portion that is to be shared with customers would be credited to customers in the succeeding year over a 12-month period, and the impact of this prior year adjustment would be excluded in calculating the subsequent year's sharing.

Structured in this way, the earnings sharing mechanism will serve as an important customer protection in the event the revenues generated by the revenue adjustment formula are greater than the Company’s actual costs, as determined in this rate proceeding. Meaning that, in this proceeding, the approved revenue requirement will include an authorized rate of return. If the PBR Plan has the result of providing a revenue allowance that is misaligned with, and exceeds, the actual cost of service, the Company’s earnings will reach and exceed the authorized rate of return in this case, indicating that an earnings-sharing adjustment is needed to protect the interests of customers.

Q. Why is the Company proposing to trigger earnings sharing after the initial 25 basis points over the authorized ROE?

A. This approach is consistent with the settlement agreement approved by the Commission in the Company’s 2009 rate case, Docket No. DE 09-035. In that proceeding, the Company had an authorized ROE of 9.67% and earnings sharing was triggered in the event that actual earned ROE exceeded 10%, or 33 basis points above the authorized ROE. Similar to that settlement agreement, the Company proposes here that earnings sharing would be triggered in circumstances where the actual earned ROE exceeds 25 basis (rather than 33) above the authorized ROE that results from this proceeding. To make this determination, the Company will calculate the amount of annual change to its distribution revenue that would be necessary to reduce its ROE to 25 basis points above the authorized amount and reduce its distribution revenue by 75 percent of that amount. The reduction will take effect coincident with other adjustments to PSNH rates, will remain in effect for a year, and be applied in equal proportion to all customer classes. Lastly, the Company will calculate the earned return on equity based on an equity ratio equal to the lesser of the Company's actual equity ratio and the equity ratio reflected in the capital structure included in rates as authorized in this proceeding.

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

A. No, this is a risk factor that the Company is proposing for the four-year term of the proposed PBR Plan. Consistent with the Company's objective to provide customers with benefits under the PBR mechanism, the Company proposes to assume the risk of earning a lower ROE than the authorized ROE during the initial PBR term (August 1, 2025 through August 1, 2029).

However, as described below, the Company is proposing that the Commission establish an opportunity for the Company to propose a continuation of the PBR Plan for a term up to and including four years beyond August 1, 2029. Where the PBR Plan is allowed to be extended, the Company proposes that the earnings sharing mechanism allow PSNH to file for a base-rate adjustment in the event that its earned ROE falls below seven percent for two consecutive quarters, at which point the Company would be allowed to file for a base rate adjustment during the extended term.

F. Exogenous Cost Factor

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

A. Over the course of a four-year PBR term, there is the possibility that events external to the Company could cause a cost change of significance that could upset the balance of the PBR Plan. For this reason, a common guardrail established for PBR plans is an "exogenous cost" factor.

In this case, the Company proposes to include a provision in the PBR mechanism to allow rates to be adjusted for significant changes in costs that would not otherwise be accounted for in the PBR mechanism. For purposes of the PBR mechanism, "exogenous costs" would be defined as positive or negative cost changes that are beyond the Company's control and not reflected in the calculation of GDP-PI. The Company would include any such request for exogenous event cost recovery in its annual PBR compliance filing. The following are examples that would qualify for recovery as an Exogenous Event (whether positive or negative): (1) State Initiated Cost Change; (2) Federally Initiated Cost Change; (3) Regulatory Cost Reassignment; or (4) Externally Imposed Accounting Rule Change.

The preceding list is not comprehensive but provides examples of types of events that are outside the Company's control. With an occurrence of a qualifying Exogenous Event, the Company will be allowed to adjust distribution rates upward or downward (to the extent that the revenue impact of such event is not otherwise captured through another rate mechanism that has been approved by the Commission) if the total distribution revenue impact (positive or negative) of all such events meets or exceeds a threshold significance of $1.5 million. If the threshold is reached, the Company would qualify for recovery (or refund) of the quantified, qualifying costs without deducting any amounts below the threshold. Exogenous event costs can be ongoing or discreet and non-recurring. The Company proposes to reflect ongoing exogenous event costs as a change in base distribution rates and that a non-recurring exogenous cost would be collected through a separate, ideally already-existing reconciling factor or as an amortized expense.

Q. Please describe the basis for the Company's proposed $1.5 million exogenous cost threshold.

A. The Commission previously established an exogenous cost threshold of $1 million (Order No. 25,123, at 38-39). Given recent experience with inflation, the previous threshold should be escalated for this PBR term. This threshold level for exogenous event costs is in line with the level previously accepted by the Commission for exogenous event costs.

The Company is proposing that the exogenous event cost threshold of significance be set at $1.5 million for calendar 2025, but thereafter would be adjusted for inflation based on changes in GDP-PI, as measured by the U.S. Commerce Department.

Q. Are there any circumstances that the Company anticipates occurring within the foreseeable future that would meet the criteria for exogenous event cost recovery?

A. Perhaps. The purpose of the exogenous cost component of the PBR mechanism is to address unanticipated or uncertain and significant changes in costs that are beyond the Company's control. Currently, there are two matters that could trigger the exogenous events recovery mechanism: costs to implement functionality related to the Puc 2200 rules governing municipal aggregation, and the New Hampshire Statewide Data Sharing Platform. Both of these items are legal mandates, but the costs to see them fulfilled are at this time are both unknown and have the potential to be substantial enough to exceed the exogenous events threshold. One other possible, though unlikely consideration for inclusion as an exogenous event would be if net metering or energy efficiency programs expand so significantly beyond today's levels as a result of expanded or newly implemented state-mandated programming over the course of the PBR term that depresses the level of sales volumes experienced by the Company that would otherwise provide revenues to support the implementation of such programs and exceeds the threshold exogenous events amount, the Company proposes that the resulting lost revenues qualify as an exogenous event eligible for recovery.

As described elsewhere in this testimony the Company has proposed a symmetrical revenue decoupling approach in this proceeding, but the Company is not recommending that the Commission implement revenue decoupling. The Company is proposing that, as part of the PBR Plan, the Company forego the revenue decoupling mechanism and bear the risk of lower revenues resulting from net metering or energy efficiency programs aside from that limited, unlikely, and extreme circumstance described in the previous paragraph. By the same token, if revenues increase as a result of increased electrification, the Company will receive increased revenues that will help to offset the cost increases associated with serving increased load.

G. Performance Metrics

Q. Is the Company proposing to institute performance metrics as part of the proposed PBR plan?

A. Yes. With the Commission's approval of the PBR plan, PSNH will be authorized to continue to move forward with its commitments for a more reliable, resilient grid, coupled with strong incentives to control the costs of system investments and operating costs to maintain stable, efficient customer rates. With approval of the proposed PBR plan, the Company proposes to implement numerous individual metrics within certain performance categories that will provide transparency in relation to the Company's performance, allowing the Department and other stakeholders to gauge the Company's progress on its PBR plan commitments. The metrics are designed with the specific intention to yield information and insight into the Company's activities and progress in specified areas of interest. In addition, the Company is proposing a set of service quality metrics designed to ensure that the Company maintains its high service quality standards during the PBR term and provide incentives to the Company to invest in manner that cost efficiently benefits customers through improved reliability and resiliency. The Company's proposed service quality metrics include baselines that if not achieved will result in penalties assessed against the Company and distributed to customers as a credit in the subsequent year.

H. PBR Term and Annual PBR Filings

Q. What is the term that the Company is proposing for this PBR Plan.

A. The Company is proposing to implement a four-year PBR Plan that would commence on August 1, 2025 and run through August 1, 2029, when the Company would then become eligible to file for a change in base rates. This term would encompass three annual PBR adjustments, occurring on August 1, 2026, August 1, 2027 and August 1, 2028.

Q. Would the Company make an annual filing to implement the annual PBR mechanism rate change and demonstrate progress on the performance metrics?

A. Yes. For each year that the PBR mechanism is in effect, the Company would submit an Annual PBR Plan Compliance Filing to the Department on or before April 1st of each year, for implementation of new rates on August 1st. The compliance filing would be formulaic, following the revenue adjustment formula approved in this case. The annual compliance filing would not involve a level of complexity anywhere close to the historical step adjustments and would include, among other things: (1) the calculation of the annual revenue-cap adjustment and capital revenue adjustment (K-bar); (2) the new proposed rate using the PBR formula; (3) an earnings-sharing computation; and (4) bill impacts of the new rate by rate class. Although the Company views an exogenous cost change as a rare occurrence, any request for exogenous cost recovery would be made in the annual compliance filing following consultation with DOE and OCA. The Company would also report information on the level and type of capital additions completed in the prior calendar year. The first annual compliance filing for the PBR mechanism computation would be submitted to the Department on or before May 15, 2026, for effect on August 1, 2026.

I. Request for Extension of the PBR Plan

A fundamental precept of the PBR Plan is that it is designed to provide a source of funding for the Company's operations and increasing capital investment, while establishing rates that change over a steady trajectory, rather than implicating the use of base-rate filings and associated step adjustments that have the impact of substantial bill changes for customers. If the PBR Plan is working well and the proper balance between the Company's funding needs and customer affordability and rate stability is achieved, it may be that the Company and/or other regulatory stakeholders will view continuation of the PBR Plan to be in the interests of customers, rather than implementing a base rate change upon the expiration of the four-year term. The Company is committed to remain under the PBR Plan term for so long as the balance between the Company and customers is maintained as this outcome would be the optimal solution for maintaining adequate funding of the system, with maximum rate stabilization over time.[12]

Accordingly, the Company is requesting that the Commission provide the opportunity for the Company to submit a request for extension of the PBR Plan for up to an additional four-year term in lieu of the filing of a new base-rate petition. The Company proposes that its request for extension would need to be filed (and ruled on) at least six months in advance of August 1, 2029, so that if the request is rejected, the Company has time to prepare and file a request for a change in base rates for temporary rates effective August 1, 2029. The Company contemplates reviewing any such request with DOE and OCA prior to submission to the Commission to leverage the potential that there may be a consensus

[12] As noted above, the Company is proposing that in the event that the PBR Plan is allowed to be extended, PSNH would be eligible to file for a base-rate adjustment in the event that its earned ROE falls below seven percent for two consecutive quarters, at which point the Company would be allowed to file for a base rate adjustment during the extended term.

recommendation for the Commission. Thus, the Company proposes that its request for extension would be filed with the Commission no later than December 1, 2028, providing the Commission with 60 days for consideration, with a decision on extension issued no later than February 1, 2029.

VI. DISCUSSION OF HISTORICAL STEP ADJUSTMENTS

A. Overview of Operation and Effectiveness of Step Adjustments

Q. What is the Company's perspective as to the historical context and justifications for the introduction of step adjustments?

A. In New Hampshire, there is a long history of the use of "step adjustments" to address earnings attrition between base-rate proceedings. For PSNH, the Commission addressed this issue in some detail in Docket No. DE 09-035, which was a base-rate proceeding resolved by settlement. In that case, the Company presented evidence to the effect that "earnings attrition was a substantial and pervasive problem" that it sought to address in that case. Order No. 25,123 at 1 (June 28, 2010).

In the settlement agreement resolving that docket, new distribution rates would take effect July 1, 2010, representing an increase in PSNH's annual revenues of $45.5 million. Order No. 25,123, at 6. Among several other resolutions, the settlement agreement established: (1) an annual increase to cover a revenue deficiency of $40.6 million; (2) an initial step increase of $12.2 million, also effective July 1, 2010; and (3) a series of additional step increases for effect on each July 1 in 2011, 2012 and 2013. Id. These sequential step increases were intended to "account for a return on additions to the Company's net plant as well as a return on capital additions resulting from the Company's REP-related activities." Id. at 6.

Under the settlement agreement, PSNH was obligated to file documentation by April 30 of 2011, 2012, and 2013, demonstrating the change in its net plant between April 1 of the prior year and March 31 of the current year. The actual change shown by PSNH would then be compared to forecasted increases derived from its February 2010, five-year forecast. If the amount of the change was equal to or greater than the amount forecasted, the designated step increase would take effect on July 1 subject to certain conditions. Each annual filing, PSNH was subject to the review of the then-Commission Staff (now DOE) and the OCA. The step increases established by the settlement agreement were contingent upon the approval of the Commission that the plant additions were prudent, used and useful and providing service to customers. The amounts of the agreed-upon step increases were associated with 80 percent of the "non-REP" changes in net plant. Id. at 6-7.

According to PSNH, the components of the settlement agreement were derived from standard ratemaking principles regarding revenue requirements and expenses, augmented by the need for some forward-looking changes to address earnings attrition between rate cases. Id. at 17. According to PSNH, in its prior rate case, PSNH was permitted a step increase in its rates, but the benefits of that [single] increase were undone by rapid attrition. PSNH testified that the settlement agreement in Docket No. 09-035 represented a balancing of the issues raised in the case and was a "cutting edge" way to address the issue of attrition. Id.

The Settling Parties described the function of the step increases as eliminating regulatory lag on the recovery of new capital additions between rate cases. The Commission noted on page 18 of Order 25,123 that the settlement agreement did not completely eliminate lag because PSNH would collect in future years the costs associated with prior year plant investments. PSNH stated that the willingness to address changes in net plant over the term of the settlement agreement was a "key component" in making the rate plan effective. Id. As to the threshold numbers used to determine whether the step increases will be permitted, the settling parties stated that net plant was the chosen measure because it is readily available to the Company and is easily reviewable by all parties. Id.

In the same order the Commission discussed the issue of "earnings attrition," as follows:

> Erosion in earning power of a revenue-producing investment. This erosion is a complex phenomenon, the result of operating expenses or plant investment, or both, increasing more rapidly than revenues. If attrition occurs, the result would be that the rate of return realized in the future would be below that which rates were designed to produce. **This effect is apt to occur in a period of comparatively high construction costs when new plant is being added ….** As the high-cost plant comes into service, it tends to increase the applicable rate base at a more rapid pace than the resultant earnings, and the rate of return decreases accordingly. According to the New Hampshire Supreme Court, "If the existence of attrition can be established by the company the commission should evaluate the impact of this factor on the earnings of the utility and make an appropriate allowance for it."

Order No. 25,123, at 29-30 (emphasis added; citations omitted).

The Commission found that the adjustments and allowances in the settlement agreement were reasonable. The Commission further found that, if it should turn out that attrition does not continue in the future, the settlement agreement's earnings sharing mechanism provides a means of protecting customer's interests. Order No. 25,123, at 30. Further, the Commission stated:

> In its filing, the Company stated that there was evidence of attrition eroding its earnings. Specifically, it contended that **it continues to make additions to its rate base and that there has been a decline in overall kilowatt-hour sales.** Thus, its investments and expenses are increasing as its revenues are stagnating or declining. Moreover, the Company indicated that given the age and condition of its plant, the need for replacements and upgrades to its system is growing.

Order No. 25,123, at 30 (emphasis added).

With respect to the sequential step adjustments allowed in 2011, 2012 and 2013 by the settlement agreement, the Commission stated:

> The settlement agreement also calls for step increases throughout the term of the settlement agreement to further guard against negative impacts on earnings caused by attrition. We have previously employed step adjustments to rates as a means of ensuring that a regulated utility retains its ability to earn a reasonable rate of return after implementing large capital projects that increase the utility's rate base after a test year.

Id. at 31, citing, Eastman Sewer Company, Inc., Order No. 24,989, at 7-8 (July 24, 2009); Forest Edge Water Co., Order No. 25,017, at 8 (Sept. 23, 2009).

Lastly, in approving both permanent rates and the subsequent series of steps, Order No. 25,123 relied upon the New Hampshire Supreme Court's position on earnings and attrition, which at its core is that RSA 378:7 does not simply refer to fixing rates at a certain point in time, but instead directs the Commission to fix rates in a manner that ensures sufficient earnings for some time into the future, which includes accounting for attrition if attrition can be demonstrated.[13]

The voluminous New Hampshire precedent on this issue dating back to the 1980s establishes that a foundational feature of New Hampshire's ratemaking framework is to set rates that are designed to "hold their own" in terms of producing a fair and reasonable return over time, motivating the need for a step adjustment or other mechanism to address earnings attrition between rate cases. Over time, the form of the ratemaking mechanism implemented to address earnings attrition has evolved in response to industry trends. However, the Commission's approach has consistently focused on the same central premise, which is to provide revenue support between base-rate proceedings, while recognizing that customers will benefit from the greater rate stability afforded by the fact that the alternative would be more frequent, sequential base-rate proceedings allowing updates to the entire cost of service each time.

In a base distribution proceeding, rates are set in accordance with well-established legal and ratemaking principles at a level designed to collect the utility's demonstrated cost of service. Specifically, base rates are set at a point in time based on a historical test year, adjusted for known and measurable changes so that the utility will have an opportunity (but not a guarantee) for the revenues produced after the rate case to be sufficient to cover the

[13] New England Tel. & Tel. Co. v. State, 113 N.H. 92 (1973).

utility′s cost of service, including a reasonable rate of return required to attract capital necessary to make needed investments in the system. This core principle is the foundation of, and driving force for, the Company's PBR Plan, as proposed in this filing.

Q. Please describe the incentives inherent in a step adjustment framework.

A. Between rate cases, utilities are incentivized to control their overall cost of service to operate in alignment with the level of revenues provided through base distribution rates, as adjusted for sales volume changes over time. When sales volumes are increasing at a level that is commensurate with the rate of increase of in the cost-of-service for utility operations, the utility can avoid frequent rate cases (and attendant base distribution rate increases), because the increased revenues produced by increased sales volumes assist in offsetting the increasing utility costs of O&M expense and capital-related expenses and taxes. In other words, for an electric utility, if electricity consumption is increasing at a pace that is commensurate with the utility's cost of doing business, there would be a lesser imperative to supplement base distribution rates with other revenue support mechanisms, such as a step adjustment. With increasing sales volumes, the incremental distribution revenue produced by increasing sales volumes would help to support the incremental capital additions that are placed in service between rate cases.

At present, utilities across the country and particularly in the Northeast are experiencing vastly different circumstances. The utility cost-of-service is increasing at a pace far greater than any change in sales volumes despite widespread conservation, energy efficiency, and even considering greater electrification of various sectors. On the cost side, cost pressures are emerging due to aging infrastructure and increasing customer expectations for a resilient and reliable electric grid in the face of significantly higher O&M expense arising mainly due to inflationary trends, causing increases in all aspects of the utility's cost of service, including interest expense, materials and supplies, contractor rates, wages and salaries and vegetation-management expense. Conversely, revenues that are generated by incremental sales volumes are not increasing at a level nearly close to historical experience, due primarily to successful energy efficiency and conservation initiatives, improved building codes and construction standards, and installation of behind-the-meter distributed generation to name several salient factors.

The historical data shown in Table 3, below, provides the Company's sales volumes in kilowatt-hours (kWh) and the average number of customers for the years 2000 through 2022, with the current year percentage increase/(decrease) when compared to the prior year. This data demonstrates that year-to-year increases of approximately two to four percent are diminished to almost zero, or even less than zero on a year-to-year basis.

Table 3: History of Electric Sales

Year-end	Sales (kWh)	% In/(De)	Avg Customers	% In/(De)
YE 2000	7,136,000,000		433,937	
YE 2001	7,414,000,000	3.75%	439,750	1.32%
YE 2002	7,403,000,000	-0.15%	447,614	1.76%
YE 2003	7,751,000,000	4.49%	454,769	1.57%
YE 2004	7,991,000,000	3.00%	473,015	3.86%
YE 2005	8,140,369,180	1.83%	480,558	1.57%
YE 2006	8,034,222,946	-1.32%	486,861	1.29%
YE 2007	8,131,594,027	1.20%	491,133	0.87%
YE 2008	7,925,888,042	-2.60%	492,882	0.35%
YE 2009	7,749,919,681	-2.27%	493,226	0.07%
YE 2010	7,846,980,937	1.24%	496,757	0.71%
YE 2011	7,815,493,020	-0.40%	498,216	0.29%
YE 2012	7,820,865,362	0.07%	500,089	0.37%
YE 2013	7,937,914,819	1.47%	501,456	0.27%
YE 2014	7,886,090,417	-0.66%	504,040	0.51%
YE 2015	7,926,578,548	0.51%	503,321	-0.14%
YE 2016	7,859,762,231	-0.85%	508,018	0.92%
YE 2017	7,758,027,152	-1.31%	513,319	1.03%
YE 2018	7,679,679,300	-1.02%	517,358	0.78%
YE 2019	7,685,130,720	0.07%	520,880	0.68%
YE 2020	7,675,174,361	-0.13%	525,947	0.96%
YE 2021	7,781,834,568	1.37%	530,036	0.77%
YE 2022	7,789,527,198	0.10%	533,906	0.72%
YE 2023	7,557,137,337	-2.98%	537,202	0.62%

More specifically, Table 3 shows that -- from 2000 through 2005 -- the Company experienced sales growth at an average rate of 2.6 percent, providing a reliable increase in revenues to support the Company's cost of service changes without motivating the need for a base-rate change. Conversely, from 2006 through 2022, the Company experienced an average sales decline of (0.25) percent, while operating costs continued to increase for myriad reasons. In the absence of a non-base rate revenue support mechanism between rate cases, utilities in this position would have no recourse but to fall into a pattern of more frequent rate cases to increase operating revenues to align with its costs.

In New Hampshire, step adjustments have been consistently used as a revenue support mechanism between rate cases to provide additional revenue support for a specified component of the utility's cost of service (primarily capital-related costs), to avoid more frequent rate cases in which all components of the cost of service are updated, including O&M and capital. Step adjustments provide incremental revenue support to the utility and afford customers a level of rate stability as opposed to the "lumpy" base distribution rate changes that follow from a full rate case.

Q. Is the Company proposing to continue with step adjustments between rate cases as a mechanism to support utility operations going forward?

A. No, the Company is not proposing step adjustments as a part of this rate case. Although step adjustments have historically served as a means of providing incremental revenue to support utility operations following a base-rate proceeding, the Company's recent experience, highlighted in particular by the magnitude of the rate increase necessitated in this rate proceeding, demonstrates that step adjustments are no longer a sufficient or efficient mechanism to achieve the objectives contemplated for the mechanism, which is to address earnings attrition by providing adequate revenue support between base-rate proceedings.

Q. What evidence is there to suggest the step adjustments have not worked and will not work going forward?

A. The Company's earned ROEs since the time of its last rate case are shown in Table 4, below. These results include the impacts associated with each step adjustment, as well as base rates inclusive of an authorized ROE of 9.3 percent. As shown in Table 3, below, the Company's ROE fell below its authorized ROE every year since rates were approved, and dropped precipitously from 9.24 percent in 2021 to 6.4 percent in the test year of this proceeding, just two years later (290 basis points below the authorized return).

Table 4: Distribution Return on Equity

Distribution Return on Equity 2019-2023	
2019	8.07%
2020	8.41%
2021	9.24%
2022	8.08%
2023	6.40%

In addition, the annual step adjustment process has proven to be time consuming and contentious among the parties despite the step being a negotiated and agreed-upon settlement term, including frequent disputes over the amount of the step adjustment; which investments should or should not be included in the step; and how the adjustments are calculated. Given these complications, it is no surprise that, despite the rate relief that the step adjustments were designed to provide, earnings attrition is persistent and the steps have fallen short of achieving their objective.

Moreover, the step adjustments from Docket No. DE 19-057 were, by design, limited in a way that resulted in insufficient revenues for PSNH to have an opportunity to earn its authorized return. That is because: (1) the steps were capped based on forecasted expenditure, as of the time of the prior rate case; (2) the rates effective date of the step adjustments were significantly lagged from when the plant went into service, which is the point in time when the Company begins to incur depreciation expense associated with the steps;[14] and (3) the step adjustments excluded capital additions associated with customer load growth. While, in theory, the exclusion of growth capital is not detrimental to the earnings attrition situation, there has to be sufficient customer revenues to offset the incremental costs of that growth. In reality, revenues from that new customer rarely exceed or even meet the level of incremental cost incurred in the early years when the asset base and the associated carrying costs are at its highest levels. As a result, the exclusion of customer growth projects from the step adjustments has a debilitating effect on the earnings attrition experienced by the Company.

As the Company looks ahead, seeing the need for significant infrastructure investment on the PSNH system, step adjustments will not adequately pace with the level of investment. This dynamic will contribute to significant earnings attrition during rate-case intervals, even with step adjustments, and will contribute to sharp increases at the time of a rate case. This is exactly the experience that the Company has had over the past four years, where large amounts of capital investment not covered by the step adjustments and now must be incorporated into base rates producing in a sizeable increase in customer rates and material bill impacts.

B. Recommendation in Lieu of Commission's Approval of the PBR Plan

Q. What is the Company's proposal with regard to step adjustments if the Commission opts not to approve the Company's proposed PBR Plan in this proceeding?

A. PSNH strongly recommends that the Commission approve the Company's PBR Plan, as proposed in this proceeding because it would establish an integrated set of risks, incentives, and support mechanisms that would serve the interests of customers over the long term. If the Commission opts not to adopt PBR, the Company proposes to implement step adjustments for effect beginning August 1, 2026, based on plant additions in 2025; and on August 1, 2027, based on plant additions in 2026. The Company's permanent rate request in this proceeding includes estimated plant additions in 2024, which will be updated during the course of this proceeding. Should the Commission accept the Company's proposal to include 2024 plant additions in the permanent rate change to take effect on August 1, 2025, then a step adjustment for 2024 plant would not be needed. If, however, the Commission does not accept plant additions through the end of 2024 then the Company would require a step adjustment to go into effect on that same date (August 1, 2025), capturing 2024 plant additions. This would follow from the result of the Company's most recent rate case. in Docket No. DE 19-057. The Company proposes that, in this scenario, the Commission modify the step adjustment process as follows, should it reject the Company's PBR Plan, as proposed:

1. Reform the format of the step adjustment to a reconciling mechanism. One dispute in recent step adjustment proceedings has been which projects to include and whether those project investments were prudently incurred. To properly evaluate the answers to these questions, it is necessary to have time. Delays in the current step adjustment process lessen the rate relief value of the step. Implementing the step adjustments as a reconciling mechanism, rather than as a going forward adjustment to base rates, would allow for the step adjustment revenues to begin flowing, subject to reconciliation once the DOE and the Commission have concluded their review of the underlying capital additions and the appropriateness of inclusion in the step.

2. Allow for all prudently incurred capital to be reflected in the step adjustment. Rather than eliminating certain capital project categories or capping those categories based on previous forecasts that become stale over time and do not reflect the actual costs to be incurred, the step adjustments should encompass all capital additions for the calendar year. There is no methodological basis for excluding customer growth projects where the revenue from those projects is insufficient to support the incremental cost.

3. Allow for the rate changes to take effect for PSNH on August 1 of each year. Allowing the rate changes to take effect on August 1 of each year would align the step change with other rate changes; would provide regulatory certainty critical for utility planning; and would allow time for the Company to compile requisite documentation in support of the step. This timing would also enable the recovery of costs beginning January 1 of the current year in order to mitigate but not eliminate regulatory lag associated with the step. For instance, the step adjustment that would go into effect on August 1, 2026 associated with 2025 would reflect the revenue requirement on 2025 investments to be incurred for the period through January 2026 through July 2027. This would allow the Company to recover the

incremental, actual costs associated with the plant placed into service in the prior year.

The Company views this modified step adjustment-as-reconciling mechanism proposal as an improvement to the current process, but an inferior model compared to the balanced and more comprehensive PBR plan proposed in this proceeding, as it does not retain the incentives inherent in PBR, and it does not yield any administrative efficiencies. Even formulating the step adjustment as a reconciling mechanism would require an annual review process of plant additions that still amounts to a mini rate case review on an annual basis. For these reasons and those that follow, the Company reiterates its support for the PBR Plan outlined above.

VII. REVENUE DECOUPLING

Q. Did the Company include a revenue decoupling alternative in its filing consistent with the settlement agreement approved by the Commission in Docket No, DE 19-057?

A. Yes. The Company has included a revenue decoupling alternative in the Rates and Tariff Changes testimony. However, although the Company has incorporated the revenue decoupling proposal in its filing, the Company does not recommend that the Commission approve the proposal for several reasons.

First, the proposed PBR revenue cap formula is intended to be a well-designed holistic mechanism that accounts for the fundamental cost drivers on the distribution system. The Company is willing to take the risk associated with lost base revenues where the PBR Plan is approved by the Commission because it will address the base drivers of the Company's cost structure, thereby eliminating the need to account for lost base revenues so long as there is no inordinate growth in the underlying activities that take revenue off the system. The Company is proposing that, should the impact of net metering increase substantially over historical levels, the Company could file for an exogenous cost change.

Second, as discussed above, one of the Company's objectives under the PBR Plan is to reduce administrative burdens for the Company, Commission, DOE, OCA and other stakeholders by reducing the scope of annual reconciling mechanisms or eliminating the mechanism. Adding a new reconciling mechanism such as that proposed with decoupling is counter to that objective.

Lastly, the purpose of a revenue decoupling mechanism is to remove the disincentive for utilities to expand their energy efficiency programs. With the passage of H.B. 549 in 2022, energy efficiency funding is now fixed by statute and there is no longer opportunity to expand energy efficiency investments beyond the level set by the Legislature.

Q. Despite the Company's position regarding revenue decoupling, can the Commission approve both the Company's PBR mechanism and the revenue decoupling proposal?

A. Yes, even though the Company recommending Commission approval of a revenue decoupling mechanism at this time, the proposed mechanism and the proposed PBR revenue cap formula are designed to work together without modification if the Commission decides to approve the revenue decoupling mechanism as well as the PBR plan. As noted in the testimony of Company Witnesses Kolesar and Ros, if the Commission were to adopt to implement revenue decoupling in this proceeding, the PBR formula would be adjusted to reflect a "customer growth" factor.

VIII. CONCLUSION

Q. Do you have any summary comments regarding the Company's proposals in this proceeding?

A. Yes. This case is immensely important for PSNH and its customers. Fundamentally, the Company has a strong service quality and cost-containment ethic, but the Company needs to recover the costs of providing a high level of service to customers through rates to sustain and bolster that ethic. Moreover, the Company continues to face an evolving business landscape. The adoption of distributed energy resources, increasing adoption of electric vehicles and other electrified technologies, and continuing evolution of media is changing the way more and more customers interact with the electric grid and their utility company. There is no avoiding the growing demand by customers and numerous stakeholder to transform the operation and management of electric distribution systems from radial, one-way power delivery systems relying heavily on physical and manual processes to monitor, assess and maintain system performance, to a two-way power delivery system enabled by electronic, computer-based equipment that can communicate information within, across and outside of the system on a secure, safe and reliable basis.

In this case, the Company is proposing an innovative approach to rate making designed to benefit customers by supporting the necessary and substantial investment in the electric distribution system to reinforce the reliability and resiliency of the system, meeting customer demand for integrating modern technologies and distributed energy resources into the system, maintaining strict control over operating expense to lower the cost of service, encouraging achievement of performance metrics measuring key outcomes, and providing rate stability. Overall, the Company is proposing a revenue requirement and associated PBR mechanisms designed to provide a more adequate level of revenue to the Company to support its operations and the continued system investment in furtherance of its public service obligations in a way that creates added customer benefits and a decreased administrative burden on all relevant regulatory entities.

Q. Does this conclude your testimony?

A. Yes. On behalf of PSNH, we appreciate the Commission's consideration of the Company's proposals in this case.