Request from: New Hampshire Public Utilities Commission

Request:

A. From the perspective of each participant, what were the historical contexts and justifications for the introduction of step adjustments?

B. Given the resources and time required to review and adjudicate step adjustment and full distribution rate cases, do the participants have thoughts or suggestions regarding how to most effectively utilize utility and regulatory resources?

C. Do the participants have recommended timeframes or methodologies for formulating step adjustment petitions?

Response:

A. From the perspective of each participant, what were the historical contexts and justifications for the introduction of step adjustments?

In New Hampshire, there is a long history of the use of "step adjustments" to address earnings attrition between base-rate proceedings. For Public Service Company of New Hampshire, 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. See, Order No. 25,123, at 1, issued June 28, 2010 ("Order No. 25,123").

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 Staff and the Office of Consumer Advocate ("OCA"), and the step increases called for in 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.[1] 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 in its Order that the settlement agreement did not completely eliminate lag because PSNH would collect in future years the costs associated with prior year plant investments. Order No. 25,123, at 18. 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. Order No. 25,123, at 18.

In Order No. 25,123 approving the proposed settlement agreement, 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

[1] "REP" refers to the PSNH "Reliability Enhancement Program," which had a separate funding mechanism. As stated in the Order, the Settling Parties clarified that the reason for setting recovery at 80 percent was the belief that the remaining 20 percent of capital additions would be for the construction of revenue producing assets. Therefore, additional revenue would offset the costs of these assets. Order No. 25, 123, at 21.

> 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. New England Tel. & Tel. Co. v. State, 113 N.H. 92, 97 (1973) (quotations omitted). 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." Id.

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 (July 24, 2009) at 7-8; Forest Edge Water Co., Order No. 25,017 (Sept. 23, 2009) at 8.

Lastly, the Commission's decision in Docket No. DE 09-035, regarding approval of the settlement agreement and the sequential step adjustments referenced New England Tel. & Tel. Co. v. State, 113 N.H. 92, 97 (1973). In that case, one of the issues on appeal by the utility was whether the commission, by ignoring the clear evidence that the company would suffer attrition in its rate of return in the future, had approved rates that will deny the company the opportunity to earn, for a reasonable period in the future, a fair return. 113 N.H. 92, at 94.

In deciding this question, the New Hampshire Supreme Court found the language of RSA 378:7 to be determinative. RSA 378:7 states as follows

> Whenever the commission shall be of opinion, after a hearing had upon its own motion or on motion of the department of energy or upon complaint, that the rates, fares or charges demanded or collected, or proposed to be demanded or collected, by any public utility for service rendered or to be rendered are unjust or unreasonable, or that the regulations or practices of such public utility affecting such rates are unjust or unreasonable, or in any wise in violation of any provision of law, or that the maximum rates, fares or charges chargeable by any such public utility are insufficient, the commission shall determine the just and reasonable or lawful rates, fares and charges ***to be thereafter observed*** and in force as the maximum to be charged for the service to be performed, and shall fix the same by order to be served upon all public utilities by which such rates, fares and charges ***are thereafter to be observed.*** The commission shall be under no obligation to investigate or hear any rate matter which it has investigated within a period of 2 years, but may do so within said period at its discretion.

RSA 378:7 (emphasis added).

Specifically, the Court held that:

> RSA 378:7 imposes on the commission the duty to determine the just and reasonable rates to be charged by a public utility for the services it renders. In making that determination, the commission must ensure that the public will not pay higher rates than are required while insuring that the rates established will yield not less than a reasonable return on the cost of the utility property used and useful in the public service.

113 N.H. 92, at 94-95, citing, New England Tel. & Tel. Co. v. State, 104 N.H. 229, 232 (1962); RSA 378:27, 28.

The Court further explained that:

> Because of the need to establish a fixed period in which to make the necessary calculations, a test year already expired is used by the commission to fix the rates under which the utility will operate for some time in the future. This necessarily imposes on the commission the obligation to fix a rate of return which will meet the constitutional standards not only at the time its order is made but for a reasonable period of time thereafter. This is recognized by RSA 378:7, which provides that the commission shall determine and fix a just and reasonable rate 'thereafter to be observed' by the utility and imposes on it no obligation to again investigate a rate matter within a period of two years.

113 N.H. 92, at 95-96.

> Accordingly, the Court concluded that:
>
> 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.

113 N.H. 92, at 97.

Based on this context, Eversource's perspective is that a foundational feature of New Hampshire's ratemaking framework is the attention paid to setting rates that are designed to hold their own in terms of producing a fair and reasonable return, i.e., constituting rates that "thereafter are to be observed" through a step adjustment or other mechanism addressing earnings attrition between rate cases, as reflected in numerous rate decisions and rate settlements approved by the Commission as far back as the 1980s. Over that period, the form of the ratemaking mechanism adopted to address earnings attrition has evolved in response to industry trends, but the Commission's approach has consistently focused on devising a method 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 as base distribution proceeding, rates are set in accordance with well-established legal principles at a level designed to collect the utility's demonstrated cost of service. As noted by the Court in New England Tel. & Tel. Co., discussed above, 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 (and not more than sufficient) to cover the utility's cost of service, including a reasonable rate of return required to attract capital necessary to make needed investments in the system.

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 is able to 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 operations and maintenance (O&M), 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 in particular 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 that might be occurring despite widespread conservation and energy efficiency. On the cost side, cost pressures are emerging due to aging infrastructure, increasing customer expectations for a resilient and reliable electric grid, vegetation management needs significantly driving higher O&M expense due to tree disease and drought, and increasing inflation effecting all aspects of the utility′s cost of service, including interest expense, materials and supplies, contractor rates, and wages and salaries. Conversely, revenues that are generated by incremental sales volumes are not increasing at a level nearly close to historical experience, due to successful energy efficiency and conservation initiatives, improved building codes and construction standards, installation of behind-the-meter distributed generation and other factors.

The historical data shown in the table 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 1: History of Electric Sales Volumes on the PSNH System

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%

More specifically, Table 1 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 average O&M cost increases of about 3 percent without motivating the need for a base-rate change. From 2006 through 2022, the Company experienced an average sales decline of (0.25) percent, as compared to the O&M cost increases of about 3 percent. With these circumstances (utility costs increasing at a rate greater than its sales volumes that drive total revenues), and in the absence of a non-base rate revenue support mechanism between rate cases, utilities 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, a measure of revenue assistance is provided in direct relation to net metering and energy efficiency. Specifically, reductions in sales revenue increases associated with

net metering and energy efficiency are partially offset by recovery of lost base revenue (LBR) correlated to those activities. However, LBR mechanisms have not proven to be sufficient to keep pace with rising costs of service based on needed capital investments and higher O&M 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), in order to avoid more frequent rate cases in which all components of the cost of service are updated, including O&M and capital. In this model, incremental revenue support is provided to the utility, while customers are experiencing a level of rate stability with rates increasing gradually over time followed by relatively smaller base-rate increases, rather than significant base distribution rate changes that would occur in the alternative putting all capital infrastructure costs and expense increases into rates at the same time.

B. Given the resources and time required to review and adjudicate step adjustment and full distribution rate cases, do the participants have thoughts or suggestions regarding how to most effectively utilize utility and regulatory resources?

As described in Section A to this response, step adjustments are a tool that has been historically used in New Hampshire to provide a level of revenue support between rate cases and to extend the interval between full base distribution rate cases (and their attendant costs, administrative burden, and rate impacts on customers). Step adjustments are typically quantified to correlate with specific categories of non-growth capital additions, rather than being more generalized revenue support mechanisms. This means that step adjustments typically involve a prudence review of the non-growth capital additions allowed for recovery through the step. As implied by the question, the prudence review aspect of the step adjustment process can be difficult to get through in the limited time frame normally allotted to step adjustment proceedings.

Other options are available to achieve the outcome of providing revenue support to mitigate earnings attrition between rate cases with differing administrative burdens. For Eversource, the mechanism selected by the Commission should reflect the Commission's preference as to how it wants to conduct the administrative proceeding. For Eversource, the important part is that: (1) there **is** a mechanism employed to allow for incremental revenue support between rate cases; and (2) the mechanism is reasonably designed to provide sufficient incremental revenue to support the capital additions that have to be implemented between rate cases to maintain the reliability and resiliency of the distribution system.

Thus, it is Eversource's perspective that regulatory mechanisms in place between rate cases should encompass the following characteristics:

1. The revenue adjustment mechanism should have a cost basis so that it is adequately formulated to provide sufficient assistance in extending the time between base-rate cases, and also avoids departing from a cost basis in the interests of customers.

2. The revenue adjustment mechanism should encompass "guardrails" that ensure that the revenues provided by the mechanism are not over-compensating the utility, while at the same time providing the utility with sufficient revenue support to sustain the opportunity to earn the authorized return on equity (ROE). For example, an earnings sharing mechanism (ESM) that is designed to trigger a rate change in the event the utility over or under earns its authorized ROE outside a pre-determined bandwidth could achieve this goal.

3. The revenue adjustment mechanism should encompass strong incentives for the utility to control costs, while providing adequate support. This can be achieved by structuring the annual revenue adjustment to work in combination with a defined stay-out period for the next base-rate change.

4. The revenue adjustment mechanism should provide transparency to stakeholders and to the Commission; and

5. The revenue adjustment mechanism should be administratively efficient.

If well designed, step adjustments can achieve these objectives, but so can other mechanisms. Step adjustments have the following characteristics:

1. Step adjustments are fully cost-based in that the step amounts allowed into base rates correlate to utility plant placed in service to customers. Thus, the step adjustment is based on the utility's actual costs it is experiencing as a result of the capital projects placed in service.

2. Step adjustments do not provide revenues in excess of the utility's costs due to the direct correlation between the step adjustment and the plant in-service. Step adjustments are calculated on a lagged basis (meaning that recoveries in the current year are for projects placed in service in the prior year) and generally exclude revenue-producing projects from the calculus.

3. Step adjustments are, in theory, designed in a way that retains the utility's incentive to control costs. Incentives to control costs are maintained because the step adjustment is providing revenue support for only ***one*** element of the utility cost of service (capital projects placed in service). Therefore, the utility remains exposed to increases in operations and maintenance ("O&M") expense that will need to be

mitigated. It is Eversource's experience that, based on current levels of capital required on the system and increased level of inflationary pressures on O&M costs, the revenues provided by the step adjustments are not sufficient to support the utility to enable longer periods between base distribution rate case proceedings. Although the incentive to control costs is present, the reality is that the step adjustments do not provide sufficient revenues for the utility to keep its head above water over an extended stay-out period – meaning that increasing cost pressures are not mitigated to an extent that an extended stay-out is enabled.

4. Step adjustments provide transparency to stakeholders and the Commission because the steps are tied to specific capital projects. In the absence of a step adjustment, stakeholders would not have as much visibility into the utility's capital additions in advance of the next base distribution rate case proceeding. In a step adjustment proceeding, stakeholders have a direct line of sight into the projects placed in service in the prior year, mitigating the amount of work that would need to be done in the next base-rate proceeding. Arguably, by reviewing segments of a utility's capital projects on a year-by-year basis cuts down on the number of projects to review in a base-rate proceeding, while increasing visibility on individual projects that might be lost in a large grouping filed in a base-rate case.

5. Step adjustments are not as administratively efficient as they could be. Although transparency may be heightened in a step adjustment proceeding in relation to individual projects, the flip side is that the step adjustment process has turned into a quasi-base-rate proceeding annually, consuming an inordinate amount of time and resources for a single tranche of projects. Clearly, this is a factor that the Commission is seeking to evaluate in this docket. The process could be streamlined and standardized, should step adjustments continue to be used in the future, so that the annual review process can be less burdensome for all parties, while retaining the positive attributes of step adjustments for all parties and customers.

C. Do the participants have recommended timeframes or methodologies for formulating step adjustment petitions?

There are three options for conducting step adjustment proceedings on a timely basis:

1. Continue the traditional model <u>with longer, specified timelines</u> for implementation following the end of a rate case, or as provided in a rate settlement. During the settlement process, trade-offs are made in devising the ultimate agreement. If the Commission has established set timelines for review of step adjustments following a rate case or rate settlement, the petitioning company and/or the settling parties

can work the financial impact of delayed step implementation into the balance of benefits incorporated to the rate filing and/or settlement agreement.

2. Reform the step adjustment to be a reconciling mechanism. In this model, the utility can make a filing and a rate could be allowed to go into effect, subject to further investigation. This is how many reconciling mechanisms work in other state jurisdictions. This provides much greater flexibility in the timeline for investigation of the prudence of capital additions addressed in the step. If costs are disallowed as a result of the further investigation, then adjustments can be made to refund to customers any amounts that should not have been recovered.

3. Allow the step adjustment based on a designated or agreed upon amount, for example 80 percent of the forecasted capital additions, and forego the prudence review until the next base-rate proceeding. The utility could be required to file documentation with each step adjustment to demonstrate that the forecast was met or exceeded, thereby warranting the revenue adjustment, but the prudence review would wait for the rate case.

With respect to these three options, Eversource recommends Option #2. Option #2 removes the time pressure associated with the prudence review, but maintains the transparency of the annual process to review capital additions. Option #2 also addresses the fact that the step adjustments are heavily lagged where the base distribution rate increase and associated revenue recovery are not effective until eight months after the calendar year in which the capital projects are placed in service. This results in a lag in revenue recovery for certain capital investments of as much as 20 months after the projects are placed in service, which contradicts the purpose of the mechanism, which is to mitigate earnings attrition.

With respect to applicable timeframes and methodologies for formulating step adjustment petitions, the process should be linked to an enhanced LCIRP process meeting the criteria described in response to Information Request 4 below, provided that the utility's LCIRP is approved in a timely manner and without excess litigation through that enhanced process. Please see the Company's response to the Commission's Information Request 4. With such an approved LCIRP, the Company believes there would be the ability to require the utilities to show the capital investments included in the step adjustment are consistent with the approved LCIRP. Once that demonstration is made, the capital projects placed in service and included for recovery in the proposed step adjustment should be allowed for recovery, with the prudency review performed either during the step adjustment proceeding or as part of the next base distribution rate case proceeding.

Request:

What feedback do the participants have on changes such as multi-year rate plans, or other solutions that could reduce or eliminate the need for annual step adjustments or decrease the frequency of rate filings?

Response:

Eversource strongly supports consideration of a performance-based ratemaking framework. Performance-based ratemaking is aimed at promoting utility investment between rate cases, while creating strong incentives for utility cost efficiency and performance on the basis of that investment.

Specifically, performance-based ratemaking is designed to:

- **Leverage the power of base-rate stay-outs to compel cost efficiency.**
  - When longer periods between base-rate cases are established, the utility is motivated to work hard to maintain cost efficiency.
  - When rates are "re-based" in the next rate proceeding, the efficiencies obtained over the stay-out period are captured in the cost of service.
  - All efficiency gains are passed over to customers through rates that are lower than would otherwise occur.
- **Support infrastructure investment through annual revenue adjustments**
  - PBR Plans incorporate an annual revenue adjustment to maintain timely and adequate recovery of capital investment for credit ratings and investment profiles.
  - The annual adjustments smooth rates over time for customers so that base-rate cases do not require stepped up rates.
- **Establish discrete performance metrics to measure outcomes for customers.**
  - Performance metrics help to demonstrate to customers their essential service is being provided safely, reliably and efficiently.

Utilities typically make investments in the system to meet expected customer demand, and to ensure the infrastructure is able to operate safely and reliably in service to our customers. Every few years rate reviews are required to ensure that the rates they charge are sufficient to cover both past and future investments and earn a return. Eversource works to keep rates as low as possible for customers by carefully managing costs.

In the jurisdictions in which Eversource operates, the ratemaking framework has taken three primary forms: (1) periodic rate base updates (such as step adjustments or multi-rate year rate plans and/or settlements), (2) annual capital-cost recovery mechanisms, or (3) annual performance-based rate adjustments. Each regulatory framework, as summarized below, is characterized by a series of trade-offs between administrative efficiency, cost-control incentives, and how closely the revenue support mechanism is linked to specific capital investments.

Periodic Rate Base Updates

Similar to the step adjustments implemented by the NHPUC in past proceedings, Eversource has experience with stepped rate increases that occur on a periodic basis to update rate base without any change to O&M recovery. Eversource refers to this construct as a "rate base update" and Eversource has this construct in place in Massachusetts as a result of a settlement process. Specifically, Eversource Gas of Massachusetts entered into a settlement that allowed for two rate-base updates over a 7-year rate plan, among other rate changes. Each rate-base "update" is comprised of an update to all elements of rate base and the associated revenue requirement, including accumulated depreciation, accumulated deferred income taxes, property taxes, and return on rate base for capital additions placed in service through December 31, 2023 and through December 31, 2026.

Annual Capital-Cost Recovery Mechanism

A capital-cost recovery mechanism would be designed to recover the annual revenue requirement on a designated set of plant additions completed each year, subject to a later prudence review, until such time that a base-rate case occurs and recovery of the cumulative set of plant additions is rolled into rate base in base rates. The design of a capital-cost recovery mechanism is critical to its ability to provide a constructive regulatory framework in which the company can operate between rate setting periods. The capital-cost recovery mechanism implemented historically in Massachusetts was severely limiting and did not eliminate the need for frequent rate cases for the utilities because of the substantial lag built into the recovery mechanism (i.e., the time elapsed between the in-service date and the start of recovery, which under the Massachusetts model could be up to 24 months). The design of the historical capital-cost recovery mechanism in Massachusetts suffered from two key debilities in an environment of increasing capital investment: (1) the amount of capital expenditures allowed through the mechanism was capped at the average of three historical years, occurring prior to the last rate case, cutting off recovery of substantial amounts of plant

additions cost until the next rate case; and (2) the cycle of recovery incorporated substantial lag between the in-service date and the start of recovery. Additionally, due to the need to produce full project documentation with each annual filing, the administrative burden was significant for stakeholders requiring rate-case level reviews of capital project documentation that could not be feasibly completed on schedule.

Annual Performance-Based Rate Adjustments

PBR is an alternate rate-setting approach that Eversource proposed in Massachusetts as a solution to the capital-cost recovery mechanism.

- Over the years, electric and gas distribution companies subject to the jurisdiction of the Massachusetts Department of Public Utilities ("MDPU") have operated under PBR or PBR-like plans because the MDPU has found that PBR better satisfies overall public policy goals and statutory obligations.

- Under the approved PBR plan, the utility is eligible for an annual revenue adjustment based on a PBR formula. The PBR formula essentially operates as an "I-X formula" which is inflation as measured by GDP-PI, plus an X factor derived on the basis of a total factor productivity ("TFP") study measuring the average cost trend for electric or gas utilities, respectively. For the annual revenue adjustment to apply, the utility must agree to a "stay-out" period of at least five years, although the MDPU has accepted a PBR Plan of up to 10 years. From Eversource's experience, the MDPU's PBR framework has motivated and enabled high service-quality levels and strong cost control for both operating and maintenance costs and capital project costs. Annual rate adjustments under PBR provide the utility with an "allowance" that essentially supports infrastructure investment, while compelling the utility to find cost efficiencies to maintain an adequate earned return over the stay-out period. Customers benefit from the strong cost control incentives when rates are "re-based" in the next base-rate case and are spared large and unpredictable base-rate increases, providing a level of rate stability.

- Under PBR, Eversource customers benefit from: (1) smaller, annual increases and reduced base-rate increases following the five-year stay-out than would have occurred through sequential base-rate increases, (2) the credit for expected future productivity gains through the application of the consumer dividend; (3) the sharing in earnings with the utility if the utility performs better than the established benchmark; (4) utility focus on system operations as opposed to frequent, lengthy, costly rate proceedings; and (5) improved transparency to stakeholders regarding annual performance on advancing state policy goals and customer service. In turn, utilities benefit from: (1) greater flexibility to plan and execute on capital investments; (2) greater incentives to be efficient and to focus on

developing innovative solutions; and (3) annual revenue allowances that offset the cost of O&M increases and/or capital project costs.

- PBR has been a better fit for customers and utilities than traditional cost-of-service rate design and the MDPU has renewed a second generation PBR plan for Eversource's electric operations as a result. In its first generation PBR approved by the MDPU in 2017, Eversource operated under a revenue-cap formula, "I − X", which provided revenue support based on an economic analysis, where "I" represents a measure of economy-wide output inflation, such as the Gross Domestic Product − Price Index, or "GDP-PI" as measured by the U.S. Commerce Department, and "X", a productivity factor that is based on the differences in productivity and input price growth between the electric-distribution industry and the overall economy. The first generation PBR included earnings sharing and exogenous cost provisions that provided adequate and appropriate economic incentives that balance utility and customer risks.

- In late 2022, the MDPU approved an extension of the PBR plan with modifications to more closely align the PBR framework with the specific utility cost structure. The MDPU approved a PBR plan that allowed for an adjustment for inflation as well as a "K-bar" adjustment that replaced the previous productivity factor approved in the first generation PBR. The "K-bar" adjustment establishes a level of eligible capital recovery based on a rolling-historical average of capital additions that were placed in service, escalated to current year dollars. Specifically, this approach more closely aligns the annual adjustments under PBR with the company-specific capital cost trend between base distribution rate proceedings.

Each ratemaking approach summarized above has the ultimate goal of providing revenue support between rate case proceedings to provide stable distribution rate changes for customers. An appropriately designed rate plan would provide a glide path for customer rates over the term of the rate plan until the company resets its cost of service through a base distribution rate proceeding. Depending on the structure of the rate plan, utilities are incentivized to control costs between the rate setting periods through stay-out provisions. Properly designed rate plans establish protections for customers and the utility through earnings sharing and exogenous provisions.

In addition to these various regulatory frameworks, each jurisdiction has established targeted cost recovery mechanisms designed to track discrete program costs on a reconciling basis. For instance, Eversource is able to recover its costs for specific programs, outside of a base distribution proceeding and reconciled on an annual basis. These programs are further summarized in response to request 6 and 8 and include, but are not limited to, energy efficiency initiatives, gas system enhancement plans to address leak-prone infrastructure, grid modernization initiatives, such as the deployment of advanced metering and electric vehicle infrastructure.

As described in response to request 1, part B, Eversource supports a regulatory framework between rate cases that provides incremental revenue, provided such a mechanism is aligned with the principles described therein.

Please refer to Eversource's responses to requests 6 and 8 for the regulatory frameworks used in Connecticut and Massachusetts that could be an alternative to New Hampshire's annual step adjustments and could decrease the frequency of rate filings.

In summary, the Company's experience has been that revenue support mechanisms in place in other jurisdictions in which it operates meet the objectives outlined above, while also eliminating the need for annual step adjustments and decreasing the frequency of base distribution rate case filings.

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. IR 22-048

Date Request Received: March 21, 2023 **Date of Response: April 20, 2023**
Data Request No. PUC 1-003 **Page 1 of 2**

Request from: New Hampshire Public Utilities Commission

Request:

Why are regular rate cases (on a rationally paced basis) not sufficient to always cover non-emergency utility capital investments, made pursuant to a utility's long-term capital plan?

Response:

In short, due to the loss of sales revenues to offset operating cost increases that naturally and inevitably arise between rate cases. More specifically, base-rate cases inherently involve substantial lag, particularly where the cost measurement is based on a historical test year, whereas the pace of capital investment is increasing so that the combination of these two dynamics results in a vast under-collection of capital investment costs, with no incremental sales revenue to offset the cost increases.

In New Hampshire, the precedent for setting base distribution rates through a base rate case proceeding has been to rely on historical test years adjusted for known and measurable changes in order to set rates coming out of a rate case. This means that O&M expense in rates is severely lagged versus actual experience by the time base distribution rates are set. Step adjustments have been utilized to update the cost-of-service post-rate case completion for one component of the cost of service (capital), but has done so on a lagged basis, such that by the time the step adjustment base rate change goes into effect, the revenue support could be lagged by a full 20 months from the date the capital project has been placed into service.

Reliance on a historical test year can provide sufficient revenue support in the ratemaking construct, provided that the sales volumes after a rate case have increased relative to the historical test year. If sales volumes have not increased sufficiently to provide additional revenues beyond that contemplated by the historical test year and cost of service (meaning, if the revenues resulting from the cost of service are limited only to the cost of service based on a lagged, historical test year), it is not possible for a utility to avoid another rate case essentially immediately after the last one, unless the utility is able to reduce its costs to operate under the lagged level of revenues provided by the rate case outcome. In a time of increasing costs and declining or fully absent incremental sales volumes, it is simply not reasonable to expect a utility to avoid multiple sequential rate cases unless there is adequate revenue support provided through other supportive rate making mechanisms. In the absence of other mechanisms, utilities will be required to file sequential rate cases to align rates with the actual cost of service, until such time that O&M and

investment costs plateau, or sales volume increases have returned.

Given the degree of increasing cost for capital investment and O&M-related expenses, the Company's perspective is that step adjustments as they are currently constituted do not provide sufficient revenues to avoid base rate cases for a meaningful amount of time. Base rate cases, without step adjustments or other forms of regulatory support between rate cases, simply will not produce sufficient revenues to support the increasing cost structure of utilities in the current environment of – as described in response to request 1 – increasing costs and decreasing revenues due to sales volume decreases from conservation and improved building costs and other demand-reduction dynamics.

Request from: New Hampshire Public Utilities Commission

Request:

What factors should be considered when evaluating the relationship between a step increase program and a company's LCIRP planning process?

Response:

The essence of this question is how a company's LCIRP planning process is determinative of the capital projects undertaken on a utility system and how an annual proceeding to give effect to a revenue adjustment mechanism should take into account the driver of the projects comprising the revenue adjustment.

The LCIRP in its current state is a forward-looking filing generally identifying a range of projects that are scheduled to be placed in-service over the next five years. By comparison, step adjustments are limited to recovery of a capped dollar amount comprised of specific capital projects in the queue for completion in the respective step adjustment year. The list of projects in the LCIRP and the projects completed in the step adjustment year may or may not be the same projects. Thus, although there is an ultimate link between the LCIRP and all projects completed on the distribution system, the step adjustments have not been devised to require a demonstration as to how the projects comprising the step adjustment tie into the LCIRP.

Going forward, Eversource strongly supports a reformation of the information provided as part of the LCIRP (or in lieu of the LCIRP if there is a change in statute) that would present a more meaningful, holistic indication of the results of the planning process applied to the New Hampshire distribution system and that would support a demonstration of prudence for plant additions presented in a rate proceeding, whether occurring in a base-rate proceeding or an interim proceeding.

The electric sector is undergoing a significant transformation -- with high penetration of DER Solar and Electric Vehicles embedded within economic development initiatives -- driving an increase in demand in New Hampshire in the near term; a need for implementation of DERMS and other evolving Grid-Edge technologies in the medium term; and the need to revisit distribution infrastructure standards in the long-term to maintain system resilience despite increased frequency and intensity of New England storms. These transformative changes have the strong potential to increase sales volumes to levels experienced historically or even greater diminishing the need for interim revenue adjustments between rate cases. However, at the same time, significant infrastructure development will need to *precede* that sales growth to enable the sales growth to

occur. Consequently, these transformative changes compel consideration of the best function and use of the LCIRP in the context of prudence reviews for plant additions on the New Hampshire distribution system as compared to the past.

A. The LCIRP process is best positioned to focus the utilities and stakeholders' attention on the overarching plan – and associated investment drivers:

1. **Base Emergent Distribution WorkPlan**: To address replacement of failed system equipment – substation and line equipment.

2. **Base Distribution Line Reliability Plan**: To modernize and in the process harden the aging condition of obsolete Distribution Lines, Poles, Line Equipment – including pole top transformers, line relocations to improve system reliability and maintain compliance with local jurisdictional requirements. Distribution Automation and other devices needed to provide greater operational visibility to perform switching actions are included within this Plan. Also included within this plan are new customer connection related distribution line work.

3. **Base Distribution Substation Reliability Plan**: To modernize protection equipment and schemes, electromechanical relays, oil circuit breakers, aging transformers with higher probability of failure.

4. **Base Peak Forecast Demand Capacity Deficiency Plan**: To proactively address capacity deficiencies on Distribution Lines (Backbone and Laterals), Distribution Bulk Substations and Distribution Non-Bulk Substations that are projected to be capacity deficient within the 10-year planning horizon. Solutions that may include both wires and non-wires alternatives would address current and future economic development as well as enable Electric Vehicle demand increase.

5. **DER Capacity Deficiency Plan**: To proactively address DER hosting capacity deficiencies on Distribution Lines, Distribution Bulk and Non-Bulk Substations and in the process increase enablement of clean energy throughout New Hampshire.

6. **Grid Modernization Investments Plan**:[1] To address new technology investments such as DERMS platforms necessary to integrate DER, VVO and CVR Technologies among others including telecom improvements to improve SCADA operational visibility and reliability, Electric Vehicle Charging infrastructure and other Grid-Edge technologies necessary to maintain reliability in the future.

[1] See, IR 15-296, Investigation into Grid Modernization, Order No. 26,575.

7. **Climate Adaptation Plan**: To address upgrades to the distribution infrastructure pursuant to evolving distribution standards – necessary to maintain and improve resilience in the future as frequency and intensity of storms in New England continue to rise.

Approval of the LCIRP by the Commission should provide directional guidance to the utilities on the seven investment classifications noted above – along with the approval of the foundational standards underpinning the justification of the seven investment classifications above. The LCIRP should also provide directional guidance to the utilities regarding these seven investment classifications informed by the level of base investment necessary to maintain reliability.

B. With the approval of LCIRP, the prudence review of individual projects included within each of those seven investment plans is facilitated. If the LCIRP filing occurs a year before the rate-case filing, the projects presented in that rate case may not arise from the approved LCIRP. However, if this process rolls forward with the LCIRP filed every 5 years – and a year prior to the next rate case filing -- eventually the subsequent rate case will involve the prudence review of specific projects and associated costs that were included in the LCIRP plans two cycles prior. At that inflection point, the LCIRP and the rate case would be connected. Mid-cycle ratemaking mechanisms would catch up to the LCIRP in advance of the rate-case cycle.

C. With the LCIRP focused on directional alignment of the Company's overall investment plans with the States Reliability and 10-year Energy Strategy, and with the eventual subsequent rate case then focused on the prudence review of individual projects included within those plans, the step increases or other mechanism could be designed to cover for revenue shortfalls that arise as a result of the factors described in the Company's prior responses in this set.

Until this process is enacted and implemented, there will continue to be misalignment between the LCIRP and step increases.

Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. IR 22-048

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Data Request No. PUC 1-005 **Page 1 of 1**

Request from: New Hampshire Public Utilities Commission

Request:

Please provide the following information (in Excel format) for all rate cases in New Hampshire since 2000:

A. Total rate base

B. Total revenue requirement

1. Total return on rate base

2. Total expenses

C. Gross Rate base increase in each step adjustment

D. Net Rate base increase in each step adjustment

E. Revenue requirements increase in each step adjustment and basis of the calculations (ROR, net or gross rate base, etc.)

F. Indicate if LRAM, Decoupling, or any similar rate mechanism/adjustments were implemented

G. Any other adjustments in revenue requirements (e.g. trackers - rate base increase, cost increase, etc.) between two rate cases. Provide details of any such changes for each year.

Response:

Please see information responsive to this request in Attachment PUC 1-005.