Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: November 05, 2024 **Date of Response: November 15, 2024**
Data Request No. PUC 2-030

Request from: New Hampshire Public Utilities Commission

Witness: Devereaux, James J., Dickie, Brian J., Landry, Leanne M.

Request:

Please provide the Company's electronic workpapers table material (with formulae and links intact) associated with **Attachment ES-ADDITIONS-3(f)** (Ref. Landry/Devereaux/Dickie Testimony Attachments; Bates Page 12,907 et. seq.). Special reference is made to labor and materials loadings components.

Response:

The Company does not have workpapers associated with Attachment ES-ADDITIONS-3(f). Attachment ES-ADDITIONS-3(f) contains project authorizations, supplements (if necessary), and closing reports that are all Power Plan generated reports without electronic workpapers. Attachment ES-ADDITIONS-2(f) is enclosed for your convenience, which includes budget and actual cost information for each project in an Excel format.

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Date Request Received: November 05, 2024	**Date of Response: November 15, 2024**
Data Request No. PUC 2-031	**Page 1 of 1**

Request from: New Hampshire Public Utilities Commission

Witness: Allen, Robert D.

Request:

Ref. Allen Testimony (Vegetation Management). Please provide summary tables, with a separate graphical response component legible when printed in black and white, presenting historical Vegetation Management spending for the 2019 to 2023 calendar years, inclusive, and the Company's forecast for Vegetation Management spending for the 2024 to 2028 calendar years, inclusive.

Response:

Please see Attachment PUC 2-031, which contains the total actual budgets for 2019 through 2023, and forecasted budgets for 2024 through 2028, including a bar graph depicting those same figures.

Request from: New Hampshire Public Utilities Commission

Witness: Allen, Robert D.

Request:

Ref. Allen Testimony (Vegetation Management). Please provide a succinct executive summary of the changes proposed for the Vegetation Management program as part of the Company's rate case proposal, and the reasons therefor.

Response:

Executive Summary

Vegetation management requires ongoing vigilance to ensure system safety and reliability. The Company's proposal for Vegetation Management is based on prioritizing programs to invest in for reliability and safety improvement, while continuing our maintenance cycle trim. While not easily quantifiable, hazard tree removal is the best tool the Company has for shoring up reliability on the system. Trees are the number one cause of outages across the system, and New Hampshire has over 4.2 billion trees (according to NH Forests and Lands). That number of trees speaks to the beauty of the New Hampshire landscape, but also the potential for trees to fail, and fall onto Company lines and onto travelled roadways. The Company is in a unique position to be stewards of this critical state resource that also poses a risk to the system: while the tree crews are trimming each circuit, they also identify failing trees and evidence of disease or insect impacts with an eye toward mitigating or preventing future system damage and outages. In total, for the years 2025-2028, the Company is budgeting for approximately $181 million in vegetation management operations as shown in Attachment PUC 2-031.

Notably, the Company will be sunsetting two vegetation management programs: Enhanced Tree Trimming ("ETT") and Full Width Clearing ("FWC") for 2025. These programs have been in effect for several years. The Company has reviewed the worst performing circuits annually and where possible, provided ETT or FWC treatment. The results of these treatments have improved both visual and physical access to the lines along with the removal of hazard trees, overhanging limbs, and non-compatible brush. However, when reviewing the list of circuits that addressed, the Company targeted the worst performers. The Company's perspective prioritizes balancing costs with reliability improvements. ETT and FWC require a larger investment than traditional maintenance programs. For 2025 and beyond, the Company's focus is that traditional maintenance programs will provide a lower cost treatment to the remaining circuits on the list without a degradation in reliability performance, making the ETT and FWC programs unnecessary, and an opportunity to harness efficiencies.

PSNH also plans to extend the maintenance cycle to up to 72 months on circuits above the Notch (serving 50,000 customers), while remaining at a maximum of 60 months for the rest of the state. This will help with managing the Vegetation Management Plan ("VMP") costs, which is otherwise difficult to achieve. The roadside tree species composition in the north country is different than the rest of New Hampshire. The growing season is shorter in duration in the north than it is below the Notch, and the trees generally do not grow as tall. An extended cycle is achievable due to the slower historic annual tree growth. The circuit schedule is designed to have an annual presence in each Area Work Center. That will not change, PSNH will still have tree crews above the Notch every year. However, by extending the cycle it will allow the Company to focus on the more impactful tree work across the state, such as hazard tree removal. The Company will route funds made available from the extended northern maintenance cycle to invest in critical hazard tree removal. For a depiction of a map of geographical outages statewide, refer to the maps on Bates page 02242.

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Date Request Received: November 05, 2024 **Date of Response: November 15, 2024**
Data Request No. PUC 2-033 **Page 1 of 1**

Request from: New Hampshire Public Utilities Commission

Witness: Traynor, Daniel M., Kishimoto, Christopher G.

Request:

Ref. Traynor and Kishimoto Testimony (Customer Operations and Digital Strategy). Please provide summary tables, with a separate graphical response component legible when printed in black and white, presenting historical Company spending for the 2019 to 2023 calendar years, inclusive, for the programs embraced by this Testimony, with itemization by program (e.g., 'New Start,' etc.) and the Company's forecast for this spending for the 2024 to 2028 calendar years, inclusive. Please provide a succinct executive summary of the changes, if any, proposed by the Company for the programs embraced by this Testimony as part of this rate case proposal, and the reasons therefor.

Response:

Please refer to Attachment PUC 2-033 for the actual and forecasted spending from 2019 through 2028.

The Company has not proposed changes to either of the Fee Free or New Start programs – in substance or structure. The only change would be the change in budget each year, as depicted in Attachment PUC 2-033. Currently, PSNH's Fee Free program is only available to residential customers and has been well received. The Company continues to evaluate potential future developments, but it is not proposing any program expansion such as extending access to commercial customers or expanding the program to allow for reoccurring payments.
For the fee free payment option, there are no proposed changes from Testimony.

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Date Request Received: November 05, 2024 **Date of Response: November 15, 2024**
Data Request No. PUC 2-034

Request from: New Hampshire Public Utilities Commission

Witness: Spanos, John J.

Request:

Ref. Spanos Testimony (Depreciation). Please provide summary tables, with a separate graphical response component legible when printed in black and white, presenting Company depreciation expense for the 2019 to 2023 calendar years, inclusive, and the Company's forecast for depreciation expense for the 2024 to 2028 calendar years, inclusive. Please provide a succinct executive summary of the changes, if any, proposed by the Company for its Depreciation methodologies as part of this rate case proposal, and the reasons therefor.

Response:

Annual depreciation expense for the period 2019 through the forecasted 2028 year does not lend itself to graphical presentation. However, the Company has created a summary table, Attachment PUC 2-034, which illustrates the annual depreciation by account. For the years 2019 through 2023, the rates by account are those currently in effect. These rates are based on the whole life method. The rates by account for 2024 through 2028 are the rates proposed in the depreciation study in this proceeding utilizing the proposed remaining life method. The depreciation study not only proposes a change in depreciation procedure but has an updated life and net salvage analysis that reflects updated analysis and informed judgment. The forecasted balances by year for 2024 through 2028 represent anticipated capital additions by year and an allocation to the account level, however, a more detailed forecast of all plant activity could not be completed because a more detailed and accurate forecast requires knowing additional information, such as the timing of removal or retirement of specific assets which will not be known until capital investments are undertaken.

Request from: New Hampshire Public Utilities Commission

Witness: Nieto, Amparo

Request:

Ref. Nieto Testimony (Allocated Cost of Service Study; Marginal Cost of Service Study). Please provide a succinct executive summary of the Company's conclusions derived from these studies, and the implications for rate design for the Company's customers.

Response:

Executive Summary:

The following is a summary of the Marginal Cost of Service Study ("MCOSS"), the Allocated Cost of Service ("ACOS") study and the key implications for rate design.

Marginal Cost of Service Study

The Marginal Cost of Service Study identifies the incremental cost associated with meeting one more unit of demand on the distribution grid, differentiating between (a) distribution substation and main trunkline feeder, (b) local distribution facilities, and (c) customer costs. The results of the 2024 MCOSS in terms of unit costs revealed the following conclusions:

- Most of the classes under-recover costs in the fixed charges, based on MCOSS results. For example, the Residential customers pay too low of a fixed charge based on marginal cost results, which prevents the customer to see efficient price signals for usage decisions. Ideally, the fixed charge would include in full the marginal monthly customer cost ($18.14) plus the monthly local facilities cost (calculated by the MCOSS as $24.76), which would amount to $42.90/month. This approach would allow the volumetric charges to only recover the costs that are directly related to incremental changes in electricity usage. It is consistent with a rate that does not include a separate per-kW of contract demand to recover local facilities costs.
- The Company has taken into account these results and has proposed to increase both fixed and usage charges for all customer classes as part of the overall revenue increase. The

increase in the customer charges ensures that the fixed charge recovers the marginal customer cost for the residential class and a portion of the local facilities costs (e.g., proposed fixed charge is $19.81/month from the current $13.81/mo.). This represents an effort to achieve more efficient rates, in alignment with the results of the MCOSS, but taking into account gradualism in changes and customer acceptance.

- The MCOSS results in terms of unit cost per distribution substation reveals that by 2028 about 32 percent of the Company's peak load located downstream of bulk substations may require capacity investments during the study period to serve station peak demand reliably, and the Company is undertaking investments to address those needs. The marginal unit cost associated with those investments is low system-wide, further reinforcing the need to move costs from volumetric to fixed charges.
- The Company generally targets summer peak load when evaluating expansion needs. This is aligned with the results of the study where the bulk of the substations peak in the summer. Nevertheless, continuing with year-round distribution time of use ("TOU") periods for the Company's existing TOU rates may be advisable for gradualism purposes, while seasonality could be targeted in future optional rates.
- For the current time-varying rate, R-OTOD 2, the MCOSS reveals that the appropriate time differentiation is 2 pm to 8 pm, in the summer months. This suggests that a modification of TOU periods would increase cost-reflectiveness of the R-OTOD 2 rate if the peak period start time was moved up by one hour and end one hour later. However, the benefit for this change is relatively small given that the current 1 pm to 7 pm peak period definition in rate R-OTOD 2 includes all core peak hours, and together with the fact that there is a very small number of R-OTOD 2 customers on this rate, the Company is not proposing a change to the peak period at this time.
- The MCOSS also reveals the appropriate differential between the peak and off-peak period. This differential is smaller than the current price spread between the R-OTOD 2 rate and the commercial on peak to off peak charges, suggesting a reduction in both rates of the peak to off peak price spread would be more conducive to cost-reflective price signals. Table 3 in Ms. Nieto's MCOSS testimony, copied below, shows the marginal unit cost for each component of the service using the existing time of day periods and the year-round construct of the existing rates. Marginal local distribution facilities costs are shown separately, in two alternative ways – per customer and per kW of monthly design or contract demand. Marginal primary costs are also shown in two alternative ways – per kW of monthly metered demand and per kWh of usage. The marginal unit cost figures have not been marked up to reconcile with the class revenue targets, but they are useful to assess the efficiency of the price differentials peak /off-peak in the current rates, and the need for a

higher cost recovery in fixed charges. The Company took into account the relative sizes of the different components in decisions regarding non-residential rate component changes.

		Local Distribution Facility Marginal Costs		Primary Distribution Marginal Cost (*Existing TOU Periods*)		
		Per cust.	Per kW		Demand	Energy
Service Classification	Customer Cost	Monthly Facilities Cost per Customer	Montly per Design Demand kW	TOU Period	Per-kW of Metered Max Demand	Restated as $/kWh
	($/Cust./mo)	($/Cust./mo)	($/kW-mo)		($/kW-mo)	($/kWh)
R-P&L	18.14	24.76	3.30	All	1.270	0.00174
R-OTOD	25.73	33.01	3.30	On-Peak	1.045	0.00837
				Off-Peak	0.225	0.00037
R-C-WH	2.96	2.64	3.30	All	1.270	0.00174
R-LCS	3.52	8.25	3.30	All	1.270	0.00174
R-UC-WH	2.91	2.64	3.30	All	1.270	0.00174
GS-P&L-P1	19.96	56.12	3.30	All	1.270	0.00174
GS-P&L-P3	36.90	156.57	1.91	All	1.263	0.00173
GS-OTOD-P1	26.04	56.12	3.30	On-Peak	1.167	0.00431
				Off-Peak	0.103	0.00022
GS-OTOD-P3	37.01	156.57	1.91	On-Peak	1.161	0.00429
				Off-Peak	0.102	0.00022
GS-UC-WH	4.48	2.31	3.30	All	1.270	0.00174
GS-LCS-P1	4.99	15.75	3.30	All	1.270	0.00174
GS-LCS-P3	11.62	9.11	1.91	All	1.263	0.00173
GS-SH	3.81	13.40	3.30	All	1.270	0.00173
GV	89.78			All	1.263	0.00173
GV-B (<115 KV)	89.76	na	n/a	All	1.263	0.00173
LG	99.23	na	na	All	1.263	0.00173

In terms of revenue requirement allocation, the MCOSS does not specify revenue targets by class, but it computes the class revenue that would result if setting those targets using equi-proportional marginal costs ("EPMC") as a reference, i.e., assuming that all classes were to pay in proportion to their respective share of marginal costs. The direct testimony, in Table 2, illustrates that the Residential Rate R is paying less than its proportional share of marginal costs while other classes, namely Rate GV and Rate LG, pay in excess relative to its marginal cost percent share. In particular:

- The residential class currently contributes to 58.47 percent of the total Company distribution rate revenues, while the residential class proportional share of total marginal costs is higher, at 73.39 percent. As stated in Ms. Nieto's testimony, a strict application of EPMC would mean that a 79% increase in the residential rates would be necessary.
- In contrast, the largest commercial classes, Rates GV and LG, are paying considerably more than marginal costs of service and rebalancing based on MCOSS would require a reduction of approximately 80 percent of their average rate.

Allocated Cost of Service Study (ACOSS)

An ACOSS provides a measure of the cost responsibility of the Company's various rate classes based on cost causation principles. The concept of cost causation is the fundamental philosophy underlying all cost studies performed for allocating costs to customer groups. The essential element in the development of an allocated cost of service methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics and the costs incurred by the utility in serving those requirements for a given test year, using FERC accounts as a measure of costs.

The ACOSS is mainly used by the Company to determine the necessary changes in class revenue allocations, while the MCOSS is used for rate design. The ACOSS reveals the required class changes in order to equalize rates of return by class. This is illustrated in Ms. Nieto's ACOS direct testimony.

- Just as in the MCOSS, the ACOSS, and in particular the minimum system study conducted by the Company agrees with the MCOSS results in that the residential customers are paying an insufficient (below cost) fixed charge. A fixed charge that would include the full ACOSS customer-related cost which for the Residential rate class would be equal to $40.93 (about $2 less relative to the figure suggested by the MCOSS). The Company has not proposed a full increase to fully reconcile the fixed charge with this value, on the grounds of gradualism and customer acceptance.

- The Company relied on the results of the ACOSS in making decisions to rebalance class revenue targets among customer classes. Mr. Davis's direct testimony includes a summary table indicating the reallocation that would be required to match the ACOSS revenue requirement results by class assuming equal ROE, as well as the proposed changes which represent movement towards ACOS results but with a gradual re-allocation. This table is copied below.

Rate Class	Current Revenue	Overall Rate Increase	Proposed Revenue at Overall Rate Increase	Proposed Revenue Using ACOS Allocators	Incremental Revenue Re-Allocation to Match ACOS Results	Incremental Percent Re-Allocation to Match ACOS Results	Recommended Percent Re-Allocation	Recommended Revenue Re-Allocation	Recommended Incremental Re-Allocation	Resulting Overall Increase
R PL + TOD	$ 244,614,943	43.48%	$ 350,975,351	$ 390,363,509	$ 39,388,158	11.2%	2.32%	$ 359,134,166	$ 8,158,815	46.8%
R LCS	$ 646,241	43.48%	$ 927,231	$ 1,960,510	$ 1,033,279	111.4%	15.00%	$ 1,066,316	$ 139,085	65.0%
R WH	$ 4,203,351	43.48%	$ 6,030,999	$ 7,762,855	$ 1,731,856	28.7%	6.00%	$ 6,392,859	$ 361,860	52.1%
G PL + TOD	$ 96,493,025	43.48%	$ 138,448,914	$ 111,046,873	$ (27,402,041)	-19.8%	-4.50%	$ 132,218,713	$ (6,230,201)	37.0%
G SH	$ 181,444	43.48%	$ 260,337	$ 227,138	$ (33,199)	-12.8%	-1.80%	$ 255,651	$ (4,686)	40.9%
G LCS	$ 50,053	43.48%	$ 71,816	$ 178,260	$ 106,443	148.2%	15.00%	$ 82,589	$ 10,772	65.0%
G WH	$ 136,044	43.48%	$ 195,197	$ 223,060	$ 27,863	14.3%	6.00%	$ 206,909	$ 11,712	52.1%
GV	$ 43,044,706	43.48%	$ 61,760,866	$ 51,575,255	$ (10,185,611)	-16.5%	-3.00%	$ 59,908,040	$ (1,852,826)	39.2%
LG	$ 21,076,873	43.48%	$ 30,241,255	$ 28,533,021	$ (1,708,234)	-5.6%	-0.40%	$ 30,120,290	$ (120,965)	42.9%
B-(GV)	$ 264,891	43.48%	$ 380,068	$ 353,101	$ (26,967)	-7.1%	-3.00%	$ 368,666	$ (11,402)	39.2%
B-(LG)	$ 1,293,214	43.48%	$ 1,855,513	$ 1,723,860	$ (131,653)	-7.1%	-0.40%	$ 1,848,091	$ (7,422)	42.9%
OL	$ 4,276,516	43.48%	$ 6,135,977	$ 4,383,545	$ (1,752,432)	-28.6%	-5.00%	$ 5,829,178	$ (306,799)	36.3%
EOL	$ 2,062,192	43.48%	$ 2,958,849	$ 1,911,386	$ (1,047,463)	-35.4%	-5.00%	$ 2,810,906	$ (147,942)	36.3%
TOTAL	$ 418,343,493	43.48%	$ 600,242,374	$ 600,242,374	$ -	0%		$ 600,242,374	$ 0	43.48%