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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-001

Request from: New Hampshire Public Utilities Commission

Witness: Landry, Leanne M.

Request:

Refer to PUC 1-003 and provide the most accelerated timeline possible for the Company to provide final 2024 numbers to the parties. Please also include a discussion of when prudency would be determined for the 2024 investments in the Company's alternative proposal submitted in PUC 1-003.

Response:

In light of this request, the Company has reviewed the feasibility of accelerating the timeline for production of 2024 capital documentation during the pendency of this proceeding. Based on this review, the Company can commit to providing the final 2024 numbers in a 2024 Capital Additions exhibit on March 7, 2025. The Company could provide capital documentation for projects completed in the first three quarters of 2024 by the end of January 2025, and documentation for the fourth quarter on March 7, 2025.

The Company's alternative proposal described in response to PUC-1-003 presented an alternative whereby:

1) The Company's original rate filing contemplated the inclusion of 2024 capital additions in permanent rates. In this alternative, the Company would remove 2024 capital additions from the permanent base rate request, lowering the request by $24 million. Permanent rates set on August 1, 2025 would recover the costs of capital investment through December 31, 2023.

2) Instead of including 2024 capital, the first K-Bar adjustment would take effect on the same date, on August 1, 2025, which is identical to how step adjustments normally work with the first step taking effect coincident with permanent rates. This first K-bar adjustment would total $44 million. In this alternative, the Company would ***not*** implement the other components of the PBR rate adjustment on August 1, 2025, because those adjustments would be duplicative to known and measurable changes addressed in permanent rates taking effect August 1, 2025.

   This proposal would eliminate the scheduling challenges with reviewing and approving 2024 additions as part of the permanent rate decision in this proceeding, by instead implementing the first K-Bar adjustment on August 1, 2025 (commensurate with permanent base rates being implemented as a result of this proceeding, having been adjusted per above to remove 2024 additions).

Alternatively, the Commission could also evaluate the 2024 capital additions on a separate and parallel path as the rate case schedule and implement a base rate change on August 1, 2025, similar to prior proceedings which had step adjustments becoming effective with commensurate with base rates in a base rate case. The Commission and parties could review the 2024 capital additions on a different procedural schedule to provide adequate time for review prior to hearings on those additions. That alternative would similarly allow for the rate case schedule to proceed as currently contemplated and to have rates implemented on August 1, 2025, that recognize the capital additions placed into service in 2024.

Request from: New Hampshire Public Utilities Commission

Witness: Horton, Douglas P.

Request:
Please provide a replacement table to that which appears in the response to PUC 1-3, and that separates the k-bar from inflation and a stacked bar version of the components.

Response:

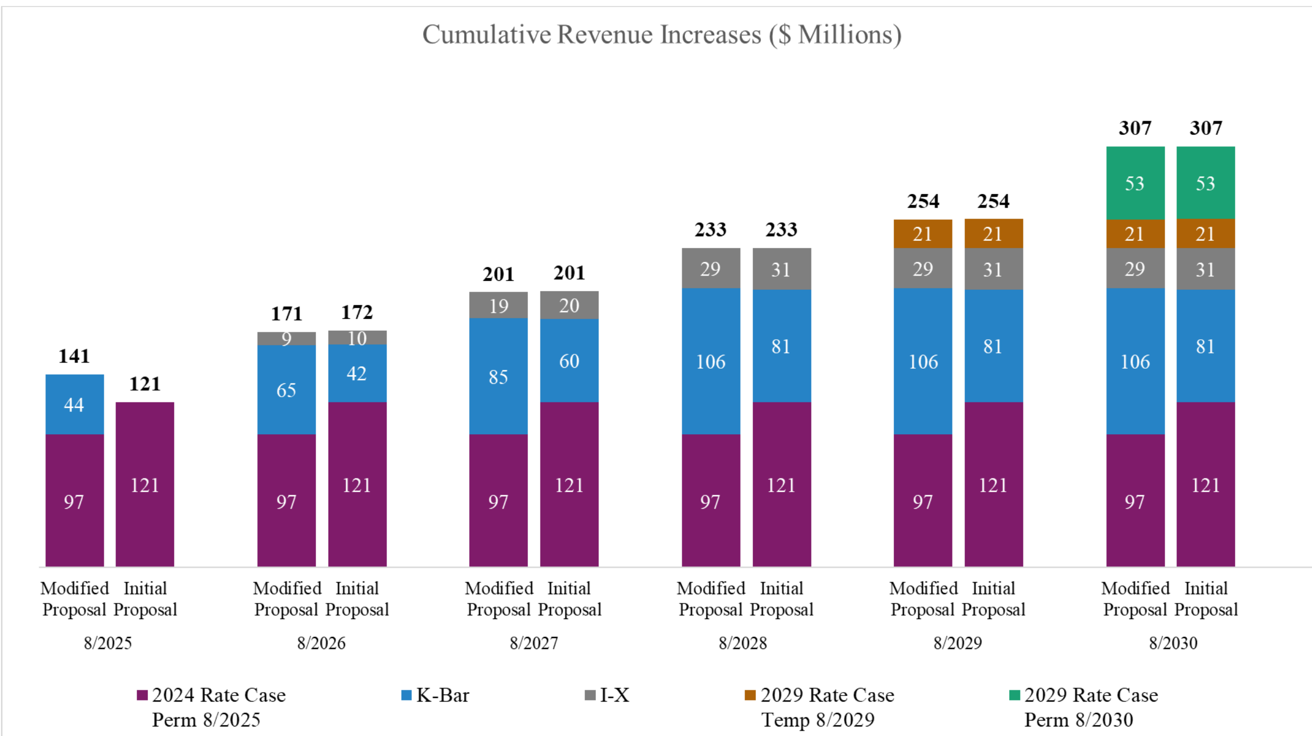
Please refer to the chart below. As discussed during technical sessions, the Company's modified proposal includes the removal of the revenue requirements related to incremental 2024 investment from Perm rates effective August 1, 2025 (estimated at approximately $24 million in the Company's permanent rate request) to be replaced by a K-bar revenue adjustment (estimated at approximately $44 million) to take effect on August 1, 2025. The first K-bar adjustment would rely on average annual investment for the years 2022-2024 escalated to 2025 dollars using the I-X formula. Though the Company's modified proposal includes K-bar revenues effective August 1, 2025, there would be no I-X revenue increase taking effect at that time. The subsequent PBR increases (both K-bar and I-X) would proceed as normal with rates effective August 1st of 2026, 2027, and 2028, consistent the Company's initial proposal.

As depicted in the chart below (all revenues are cumulative):

- The purple series at the bottom represents the incremental Perm rate increase effective August 1, 2025. As discussed above and at technical sessions, the modified proposal is approximately $24 million less than the original proposal. This bar reflects the Company's permanent rate request, as filed, of approximately $182 million, less the temporary rate increase implemented on August 1, 2024 of $61 million. Therefore, the August 2025 rate change under the Company's initial proposal is equal to $121 million ($182 million permanent rate change, less $61 million reflected in the temporary rate adjustment). This $121 million increase includes $24 million of plant additions related to 2024 capital additions, consistent with the Company's initial request. As described in the response to PUC-1-3, under the modified proposal this $24 million would be removed from the permanent rate increase, resulting a base increase of $97 (instead of $121 million), and, in its place, the first K-bar revenue requirement of $44 million would go into place, as described below.
- The blue series reflects the cumulative k-bar revenue increases, including the first increase ($44 million) effective August 1, 2025 in the Company's modified proposal.

- The gray series represents I-X revenues, where X=0 and GDPPI is approximately 2% per year. These amounts are slightly reduced in the Company's modified proposal as a result of the "going-in" revenue requirement reduction for the removal of 2024 investment from Perm rates effective August 1, 2025.
- The orange series represents the Company's next rate case, with Temp rates effective August 1, 2029
- The green series represents the subsequent Perm rate increase August 2030 arising from the Company's next rate case.

PUC TS1-002 Chart



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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-003

Request from: New Hampshire Public Utilities Commission

Witness: Horton, Douglas P., Botelho, Ashley N.

Request:

Has the Company considered a higher threshold for the exogenous events mechanism? Please provide any comparative data the company has available for other companies/jurisdictions that are similarly situated.

Response:

Please refer to Attachment PUC TS1-003 for the comparison of exogenous factors established for Performance-Based Ratemaking Plans in Massachusetts as compared to the Company's proposal in this proceeding.

In the Company's view, its proposed threshold is at an appropriate level and is consistent with prior precedent in New Hampshire for the relative materiality threshold for exogenous events in the past.

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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-004

Request from: New Hampshire Public Utilities Commission

Witness: Botelho, Ashley N., Horton, Douglas P.

Request:

Please describe the Company's proposal for each reconciling mechanism if the PBR plan were approved. In your response, please include a listing and description of all current reconciling mechanisms, what is included in the test year in this proceeding and the Company's proposal for each component going forward

Response:

Please refer to Attachment PUC TS1-004(a) for a listing of changes to current reconciling mechanisms as proposed by the Company if the Performance-Based Ratemaking Plan is adopted. This attachment was provided in the Company's response to Data Request OCA 2-017 sent to the parties on September 25, 2024.

Please also refer to Attachment PUC TS1-004(b) for a listing of current mechanisms for which the Company proposes no changes to resulting from this proceeding.

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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-005

Request from: New Hampshire Public Utilities Commission

Witness: Renaud, Paul R., Dickie, Brian J., Coates Jr., Robert S.

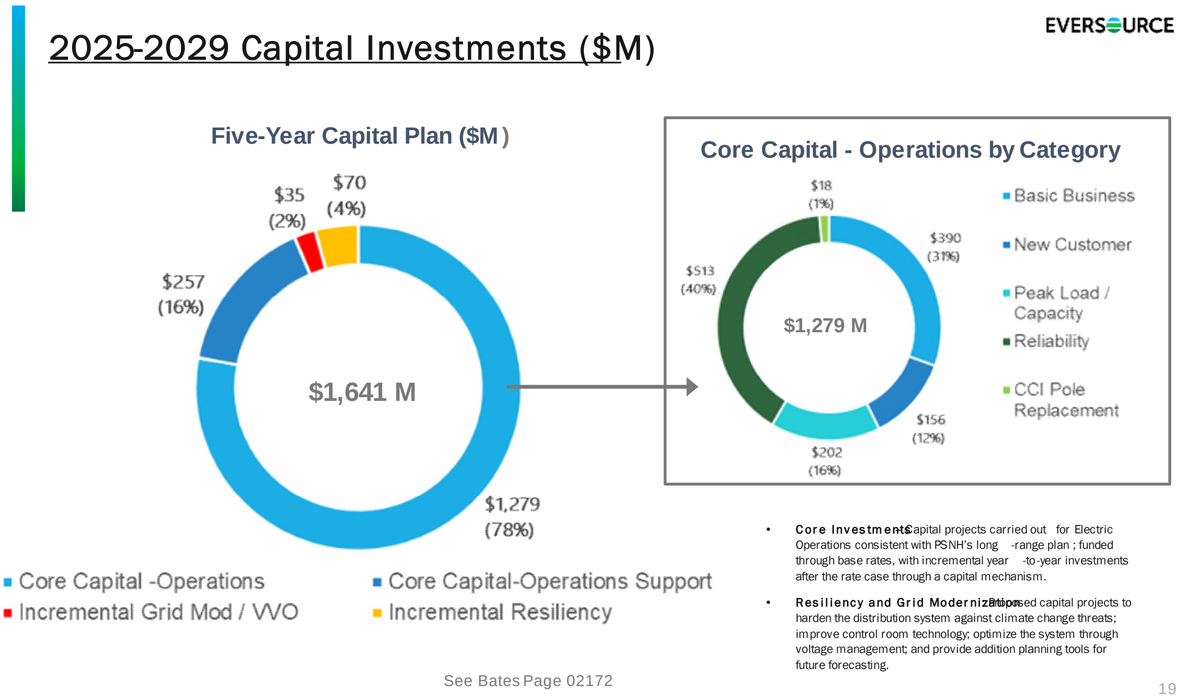
Request:

Break down the investments/budgets by category.

Response:

Please refer to Attachment TS1-005(a) for the investments by category for 2025-2029 in graphical and table form by year. Please refer to Attachment TS1-005(b) for the 2019-2023 five year budget-to-actual report by project. Attachment TS1-005(c) provides the 2025-2029 for the five-year budget by each project.

Please note, Attachment TS1-005(a) and Attachment TS1-005(c) provides the core capital investments as shown on Slide 19 (copied below) of the Company's presentation of its Distribution Solutions Plan on October 8, 2024. The incremental Grid Mod/VVO and resiliency investments are budgeted in 2025-2029 as depicted below and are not included in the attachments.



See Attachment PUC TS 1-005(d) showing grid modernization capital additions placed in service by year. For the purposes of this response, the Company used a definition of "grid modernization" that includes investments in technologies or systems that increase visibility and control of the distribution grid for the purposes of increasing reliability, integrating distributed energy resources (DER), and increasing the efficiency of power flow delivery. The investments detailed in Attachment PUC TS 1-005(d) were all included in the Company's base distribution capital plan because their primary use cases were to improve reliability and operational efficiency.

The incremental grid modernization investments proposed by the Company for the 2025-2029 period are distinct from these prior investments and are driven primarily by opportunities to improve DER integration and reduce energy and demand inefficiencies associated with energy delivery.

Below please find Table PUC TS1-005 with a description of the grid modernization projects.

TABLE PUC TS1-005

Technology Type	Description (Reference section)	Cost Reference Section/page number	Cost Description
Field Device - Distribution Automation	Installation of new remote controlled reclosers and switches	Section 5.2.2.1, Bates Page 02141	Design, build, and commission of field devices. In addition, there is ongoing maintenance of this new equipment included.
Field Device – DER Gateway	Installation of new device for the control and monitoring of DER	Section 5.4.2, Bates Page 02167	
Field Device – Capacitor Bank	Adding SCADA control to cap banks	Section 5.2.2.1, Bates page 02140-02141	
Field Device – Line Regulator	Adding SCADA control to line voltage regulators	Section 5.4.2, Bates Page 02165	
Field Device – Line Sensor	Installation of metering points on the distribution circuit to provide a feedback loop into optimization power	Section 5.2.3, Bates Page 02145	
Substation Equipment – Microprocessor relays	Replacing electromechanical relays with programmable microprocessor relays	Section 5.2.2.1, Bates Page 02141	Design, build, and commission of substation feeder breaker relays. In addition, there is ongoing maintenance of this new equipment included
Substation Equipment – LTC Controls		Section 5.2.2, Bates Page 02140	
Software – DMS	Implementation of the Distribution Management System	Section 1.2.4, Bates Page 02020	Software, hardware, services, and labor required to

Software – DERMS	Operational system to manage the monitoring and control of DER on the distribution system	Section 5.4.2, Bates Page 02167	implement this operations system. Also includes on-going vendor support and Eversource internal labor.
Software - OMS	Operational system to manage events on the system to effectively dispatch crews to respond	Section 2.4.7.5, Bates Page 02078-02079	
Software - GIS	Source database that represents the as-built equipment and conditions on the distribution system	Section 2.4.7.6, Bates 02079	
Software - iTOA	Work request tool used by System Operations to manage planned work on the transmission and distribution system	Section 5.4.3.2 at Bates Page 02169	
Software – Avtec	Communications platform used to consolidate multiple communications channels into a single user interface for efficient communications between system operators and field personnel.	Section 2.4.7.1, Bates Page 02076	
Software – Aclara	System that receives data from installed line sensors and is	Section 2.4.7.1, Bates Page 02076	

	used to trend loading at that particular location on the system		
Software - Click Mobile	Mobility solution used to communicate and process planned and emergent work with field personnel	Section 2.4.7.5, Bates Page 02078-02079	
Software - Synergi	Electric system modeling tool used to study load and generation impacts and develop long term system upgrades.	Section 5.4.3.2 at Bates Page 02169	
Software – NH Powerclerk	Customer facing tool to enter application for DER interconnection and data source for engineering and real-time power flow solutions	Section 5.4.3.2 at Bates Page 02169	
Communications – Private Radio	Base radio and end-point radio installations that are used for voice and SCADA data communications.	Section 2.4.7.1 at Bates Page 02076	Implement additional base radios to provide communications coverage to field devices and ongoing maintenance activities related to these facilities
Communications – Cellular	Implementation of cellular modems used to establish connectivity with	Section 5.2.5 at Bates Page 02147	Implementation of new cellular modems into field devices and the

	field devices over public carrier networks		ongoing cost for data with public carriers
Communications - Fiber	Creating high speed connectivity to critical locations.	Section 2.4.7.1 at Bates Page 02076	Installation of new fiber circuits and cost to maintain those circuits. In addition, there are costs for leased circuits from 3rd party vendors.

Request from: New Hampshire Public Utilities Commission

Witness: Horton, Douglas P

Request:

Please clarify how the Company intends to recover each category of investments (i.e., core distribution capital, grid enhancements(modernization), and co-optimization initiatives. Include in your response (1) how those investments will be reviewed and approved by the Commission, (2) how the costs will be recovered (3) when prudency of those investments will be determined (4) what is the administrative process for reviewing and approving each type of investment along the way and (5) what would be the cap for k-bar eligible additions under various scenarios.

Response:

Please refer to Attachment ES-DPH-2 at Bates Page 01444 for the Company's capital forecast for the years 2025 through 2027. These Core Investments are also described in Sections 5.1 and 5.2 of the Distribution Solutions Plan ("DSP"). Please also note that a modified version of this table (adjusted to include incremental grid modernization and system resiliency programs) is included at the bottom of this response, as well.

Core capital investments include the categories of Peak Load Growth and New Business, Basic Business Requirements, Aging Infrastructure, Operation Services, Engineering, Facilities, Information Technology, Customer and All Other Shared Services.

The revenue requirement associated with these investments will be recovered annually through operation of the (I-X) and K-bar mechanisms. The Company's proposal is that, core capital investments will be eligible to be included in the K-bar adjustment up to the 10 percent capital constraint for plant additions shown in Attachment ES-DPH-2 on Line 41. Please also see the Company's response to PUC-1-008 for additional discussion of, and a demonstration of, the maximum K-bar revenues if actual plant additions are at or exceed the cap. The prudency of these investments will be determined in the Company's next base rate proceeding. Accordingly, the only administrative process for reviewing and approving each of these categories of investment along the way will be the K-Bar calculation filed annually as part of the company's PBR filing.

The Company's DSP includes other non-core investment categories not included in the Company's 2025-2027 capital forecast, such as: (1) Grid Enhancements (Modernization/Resiliency) included

Sections 5.3 and 5.4 of the DSP, (2) Co-optimization of customer-driven investments in Section 5.2.4 of the DSP, and (3) Company-owned solar included in Section 5.5 of the DSP.

Because these other non-core categories of investment were not included in the Company's 2025-2027 capital forecast, the revenue requirement associated with these investments is not fully reflected in the proposed K-bar 10 percent cap. Therefore, unless an adjustment is made to incorporate the budgets for these non-core investments, pursuit of these investments will result in plant additions that exceed the cap and will not be reflected in the K-bar adjustment. The Company's proposal is that it be afforded the flexibility to pursue these investments, with an appropriate adjustment to the K-Bar mechanism, as follows.

For Grid Modernization and VVO/Resiliency, as identified below, the Company has requested the PUC indicate its support (or not) for these programs in this proceeding. As discussed during the technical session, the Company has proposed budgets for the grid modernization and incremental resiliency investments not currently included in the capital plan. If the Commission were to authorize the Company to pursue these investments, the Company has calculated a revised K-bar cap based on the five-year capital budget including the proposed grid modernization and incremental resiliency program costs as shown in the table below, and as described in the Company's response to PUC-TS-1-008. In addition, Attachment PUC TS1-006 provides an updated version of Attachment ES-DPH-2 including the grid modernization and resiliency investments to demonstrate how the cap calculation would change, if Grid Modernization and VVO/Resiliency investments are supported as part of this proceeding. The Company proposes that the prudency review of these projects would occur as part of the next base distribution rate proceeding, following the PBR term, consistent with the review for core capital investments described above. The Company, however, can provide the documentation supporting the capital additions as part of the annual K-bar filings for information purposes.

DISTRIBUTION CAPITAL EXPENDITURES INCLUDING GRID ENHANCEMENTS

		Forecast			Total
		Year 2025	Year 2026	Year 2027	2025-2027
	CORE DISTRIBUTION				
1	Operations Distribution				
2	Peak Load Growth and New Business	$ 64,163	$ 77,347	$ 76,399	$ 217,909
3	Basic Business Requirements	73,358	77,441	77,587	228,386
4	Aging Infrastructure	122,222	104,511	96,667	323,400
5	Total Operations - Distribution	$ 259,743	$ 259,299	$ 250,653	$ 769,695
	Other Distribution				
6	Operation Services	$ 15,133	$ 15,429	$ 15,291	$ 45,853
7	Engineering	6,518	6,920	14,620	28,058
8	Facilities	14,500	21,000	7,800	43,300
9	Information Technology	7,411	1,800	3,248	12,459
10	Customer and All Other Shared Services	7,677	6,462	6,734	20,872
11	Total Other Distribution	$ 51,239	$ 51,611	$ 47,692	$ 150,542
12	**TOTAL CORE DISTRIBUTION**	**$ 310,982**	**$ 310,910**	**$ 298,345**	**$ 920,237**
	INCREMENTAL PROGRAMS - GRID ENHANCEMENTS				
13	Grid Modernization/VVO	$ 5,000	$ 6,000	$ 5,000	$ 16,000
14	Resiliency	10,000	15,000	15,000	40,000
15	**TOTAL INCREMENTAL PROGRAMS**	**$ 15,000**	**$ 21,000**	**$ 20,000**	**$ 56,000**
16	**TOTAL K-BAR ELIGIBLE CAPITAL**	**325,982**	**331,910**	**318,345**	**976,237**
	K-BAR ELIGIBLE CAPITAL CALCULATION:				
17	Total K-Bar Eligible Distribution Capital Expenditures	$ 325,982	$ 331,910	$ 318,345	$ 976,237
18	Cumulative K-Bar Eligible Distibution Capital Expenditures	325,982	657,893	976,237	976,237
19	10% Capital Constraint	32,598	65,789	97,624	97,624
20	Total Capital Allowed for K-Bar Adjustment	$ 358,581	$ 723,682	$ 1,073,861	$ 1,073,861

At the technical session, the Commission expressed a concern that the co-optimization proposal provided an opportunity for the Company to ignore the constraints of the K factor and spend capital on co-optimization projects unchecked. In recognition of this concern Eversource is proposing the following administrative process for reviewing and approving each of the co-optimization projects. When a co-optimization investment is identified, the Company will file with the Commission the projected estimated costs and benefits of each project on a forecast basis for information purposes. Upon completion of each project, the Company will file the actual costs for the project, commensurate with the annual K-bar filing, to allow the Commission to conduct a prudency review and approve the inclusion of the associated capital additions in rate base, at that time. This contemporaneous review will provide the level of review and transparency to ensure the Company has prudently managed the project prior to allowance in rates in the K-Bar.

Similarly, in regards to the Company-owned solar, pursuant to RSA 374-G, the Company will submit any proposed projects for the Commission’s review prior to implementation. This process will provide adequate opportunity for PUC review and approval prior to any Company owned solar project moving forward, and prior to any costs being reflected in rates.

Cost recovery for co-optimization projects and company owned solar projects can then be facilitated in one of two ways:

1) If the inclusion of the approved capital additions in rate base for either a co-optimization project or a Company owned solar project causes the 10 percent capital constraint for plant additions in the K-bar adjustment to be exceeded, the revenue requirement associated with the approved co-optimization capital additions in excess of the cap will be included in the revenue requirement in that year.

2) Or, in the alternative, the Commission may adopt a formal targeted capital tracker process for these co-optimization and Company-owned solar investments such as the Type 1 capital regime currently included in the PBR plan in Alberta, or the EPRM mechanism for specified capital projects currently included in the PBR plan in Hawaii. The proposed administrative process for reviewing and approving these investments is essentially the same as the process for a formal targeted capital tracker.

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

Date Request Received: October 03, 2024	**Date of Response: November 06, 2024**
Data Request No. PUC TS1-007	**Page 1 of 1**

Request from: New Hampshire Public Utilities Commission

Witness: Ros, Augustin, Kolesar, Mark, Horton, Douglas P.

Request:

Provide a matrix depicting the elements/components of PBR plans for: NSTAR Electric (Generation 1), NSTAR Electric (Generation 2), NSTAR gas (Generation 1), Fitchburg Electric & Gas, PSNH (as proposed). Please include a discussion of all PBR elements/components included or excluded from the Company's proposal in this proceeding

Response:

Please refer to Attachment PUC-TS1-007 for the Company’s matrix that depicts a comparative analysis for the Company’s performance-based ratemaking (“PBR”) mechanism proposed in DE 24-070 as compared with the PBR mechanisms approved in Massachusetts.

Specifically, D.P.U. 17-05 (“PBR1”), D.P.U. 19-120 for NSTAR Gas, D.P.U. 22-22 for NSTAR Electric (“PBR2”), and D.P.U. 23-80 for Fitchburg Electric and Light Company d/b/a Unitil.

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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-008

Request from: New Hampshire Public Utilities Commission

Witness: Horton, Douglas P.

Request:

Please provide a calculation showing the maximum K-bar revenues that would be allowed for under operation of the K-bar at different levels of spending. Please include the maximum both with and without Grid Modernization. Please also describe how the incentive properties vary under a PBR framework as proposed by the Company (inclusive of a K-Bar mechanism) as compared to traditional cost of service ratemaking with periodic sequential base rate cases.

Response:

Please refer to PUC TS1-008 Tables 1 and 2 below. These tables illustrate the maximum revenue increase allowed under the Company's modified proposal for two scenarios as compared to the corresponding base revenue change enabled by the K-bar under the Company's modified proposal. This analysis was raised during technical sessions and was originally addressed in the Company's response to PUC 1-003. The two scenarios are described below.

- **Scenario 1, Maximum Total Revenue Increase (incorporating the 10% differential), core capital only.**
    - Assumes the K-bar mechanism reflects the maximum eligible capital investment, including a 10% cap on investment (i.e. the Company's current forecast plus 10 percent), reflecting core distribution capital only and excluding grid modernization and resiliency projects.
    - Annual capital investment is shown in PUC TS1-008 Table 2, Line 3.
    - Cumulative revenue increases are shown in PUC TS1-008, Table 1, Line 9, which are $2 million, $6 million, and $10 million greater than the Company's modified proposal as filed for rates effect August 1, 2026, August 1, 2027, and August 1, 2028, respectively.
- **Scenario 2, Maximum Total Revenue Increase (incorporating the 10% differential), including grid modernization and resiliency.**
    - Assumes the K-bar mechanism reflects the maximum eligible capital investment, including a 10% cap on investment (i.e. the Company's current forecast plus 10 percent), *including* grid modernization and resiliency projects.

- Annual capital investment is shown in PUC TS1-008 Table 2, Line 8, which includes grid mod and resiliency investment of $15 million, $21 million, and $20 million for calendar years 2025, 2026, and 2027, respectively (Line 5 of Table 2).
- Cumulative revenue increases is shown in PUC TS1-008, Table 1, Line 14, which are $3 million, $8 million, and $15 million greater than the Company's modified proposal as filed for rates effect August 1, 2026, August 1, 2027, and August 1, 2028, respectively.

Please note that both scenarios assume all capital expenditure is placed in-service as expended. That is, no capital expenditure is "carried over" to subsequent periods, as is often the case with larger projects, such as substation builds. In Scenario 2, all Grid Mod and Resiliency investments are allowed to flow through the K-bar mechanism, although those amounts would require separate approval by the Commission before recovery would be allowed through the K-bar mechanism. The forecasted investment for years 2025-2027 for these programs is $56 million combined, approximately $15 million - $20 million per year.

PUC TS1-008 Table 1

	($ Millions)	Rates Effective August 1, 2025	August 1, 2026	August 1, 2027	August 1, 2028
1	**Cumulative Revenue Increase**				
2	*Per Modified Proposal*				
3	I-X (X = 0)		9	19	29
4	K-bar, Per Modified Proposal	44	65	85	106
5	Total Revenue Increase (A)	44	74	104	136
6	*PBR at Maximum K-Bar (excluding Grid Mod/Resiliency)*				
7	I-X (unchanged from Line 3 above)		9	19	29
8	K-bar, Maximum	44	67	90	117
9	Total Revenue Increase	44	77	109	146
10	**Difference, Total Revenue vs (A) Above**		**2**	**6**	**10**
11	*PBR at Maximum K-Bar (including Grid Mod/Resiliency)*				
12	I-X (unchanged from Line 3 above)		9	19	29
13	K-bar, Maximum	44	68	92	121
14	Total Revenue Increase	44	77	111	151
15	**Difference, Total Revenue vs (A) Above**		**3**	**8**	**15**

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

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Data Request No. PUC TS1-008 |

PUC TS1-008 Table 2

	Annual Capital Investment ($ Millions)	2025	2026	2027	3yr Total	Reference
1	Core Investment, excl. Grid Mod/Resiliency	311	311	298	920	PUC TS1-006 Table, Line 12
2	10% cap	31	31	30	92	Line 1 x 10%
3	CAPPED Investment, excl. Grid Mod/Resiliency	342	342	328	1,012	Line 1 + Line 2
4	Core Investment, excl. Grid Mod/Resiliency	311	311	298	920	Line 1
5	Grid Mod & Resiliency Investment	15	21	20	56	PUC TS1-006 Table, Line 15
6	Investment, incl. Grid Mod/Resiliency	326	332	318	976	Line 4 + Line 5
7	10% cap	33	33	32	98	Line 6 x 10%
8	CAPPED Investment, incl. Grid Mod/Resiliency	359	365	350	1,074	Line 6 + Line 7

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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-009

Request from: New Hampshire Public Utilities Commission

Witness: Renaud, Paul R., Dickie, Brian J., Coates Jr., Robert S.

Request:

Please provide a copy of the TRC report.

Response:

Please refer to Attachment PUC TS1-009 for a copy of the TRC Report.

TRC conducted a distribution system assessment in accordance with the Docket DE 19-057 Settlement Agreement, reviewing the following areas pertaining to reliability and resiliency improvements:

- Use of distribution-class steel poles as a standard in off-road right-of-way
- Use of Class 2 wood poles as a standard in road-side primary distribution lines
- Use of spacer cable as a standard for overhead conductor
- Use of fiberglass crossarms
- Planning methods for line relocation and reconductoring activities
- Substation transformer and circuit breaker replacement processes
- Vegetation management activities, including Enhanced Tree Trimming, Enhanced Tree Removal, and Right-Of-Way Clearing, in addition to Scheduled Maintenance Trimming

The key findings are summarized below:

Figure ES-1-1. Summary of Key Findings and Recommendations by Study Topic Area

Topic Area	Key Findings	Recommendations
System Condition	• Many distribution components are beyond their expected life and require replacement to maintain system reliability and resiliency. • Substantial numbers of wood poles, circuits of primary conductor, substation breakers and substation transformers are at the end of life. • Wood poles are structurally overloaded due to their age and number of attachments. • Many circuit lines in the ROW are inaccessible due to location and difficult to maintain. • Trees and canopy are in close proximity to distribution system making the lines vulnerable to outages.	• Accelerate replacement of aged equipment (poles, conductor, substation breakers & transformers), with a systematic plan for each equipment type, based on system criticality and age. • Replace wood poles that are structurally overloaded 90% or more, with the properly sized poles in the next 10 years. • Identify candidate lines for relocation to roadside and develop 5-year plan to rebuild. • Increase vegetation management and spacer cable installation for vulnerable lines. • Consolidate current resiliency/hardening efforts into an overarching program following the decision framework outlined by the Department of Energy.

Topic Area	Key Findings	Recommendations
Substation Transformers Distribution Planning	• Standardizing substation transformer sizes can provide benefits for streamlining inventory and reducing event response time. • Eversource conducts distribution planning to maintain system operations within established operating criteria. • Engineers develop solutions to address capacity, power quality, and reliability concerns based on historical performance data and forward-looking forecasts. • Line relocation and reconductoring are two options to address reliability issues.	• Standardize substation transformer sizes wherever possible based on voltage class to allow for greater efficiency in maintaining stock of fewer transformer sizes and flexibility in responding to contingency events and coordination with neighboring state service areas. • Continue to assess to determine when circuit breakers should be used in place of circuit switchers for operational and reliability benefits. • Establish a tracking program to compare historical outage data for line segments for 3-5 years (as data is available) and then report annually on that segment post-improvement. Such a system will document the improved reliability and resiliency delivered by relocation and reconductoring projects. • Reduce the number of feeders without tie capability to allow for circuit reconfiguration and load pickup throughout the system. • Maintain awareness for distribution project cost increases that may arise as projects are delayed.

Topic Area	Key Findings	Recommendations
Steel Poles	• Benefits of steel poles include improved strength, reduced likelihood of catastrophic failure, and lower maintenance costs. • Steel poles have twice the expected useful life of an equivalent wood pole. • While upfront costs are higher, the improved longevity of steel yields a lower total lifecycle cost compared to wood poles.	• Given lower lifecycle costs and difficulty in patrolling and replacing remote right-of-way assets in the event of a failure, continue to use steel poles as the standard in these environments. • Establish a proactive program to identify and replace five circuit miles/year of wood poles in the ROW with steel, in areas susceptible to damage or failure.
Class 2, Wood Poles	• Class 2 wood poles can withstand 60% greater force than smaller-diameter class 4 poles, improving outcomes during tree strikes or high winds. • Class 2 wood poles have marginally (2-4%) higher costs than equivalent Class 3 poles. • At current failure rates, if 8-9 poles (~5%) did not fail due to use of stronger Class 2 poles, incremental costs would be negated.	Continue use of Class 2 wood poles due to low additional costs and strength improvements in severe weather scenarios

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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-010

Request from: New Hampshire Public Utilities Commission

Witness: Devereaux, James J., Landry, Leanne M., Schilling, Jennifer A., Freeman, Lavelle A., Horton, Douglas P., Walker, Gerhard, Renaud, Paul R., Dickie, Brian J., Coates Jr., Robert S.

Request:
Please provide a copy of the Business Process Audit, including a discussion of how the Company has addressed the findings from the business process audit.

Response:

Please see Attachment PUC TS1-010(a) for a copy of the Business Process Audit and Attachment PUC TS1-010(b) for the appendix.

Section 3.2 of the Settlement Agreement approved by the Commission in DE 19-057 committed the Company to engage in a business process audit ("BPA") to review the Company's capital authorization and budgeting processes and assist in developing templates for project documentation in a rate proceeding, among other objectives. The BPA was agreed to as a way to address allegations asserted by the DOE regarding the quality of the Company's capital project documentation presented for recovery in a regulatory proceeding (Settlement Agreement, § 3.2). Following approval of the Settlement Agreement, the DOE retained an outside consultant, River Consulting Group, Inc. ("RCG") to conduct the BPA.

The third-party auditor provided input regarding several aspects of the Company's capital-planning processes and the BPA Report provided 25 recommendations for improving the Company's documentation and communication in relation to its capital approval process. RCG acknowledged on page 9 of the report that these recommended actions would require commitment from all parties to structural change and constructive collaboration and communication to avoid unneeded delays in proceedings. The Company has integrated the 25 BPA recommendations into its processes on a going forward basis and as applicable. Below, each of the 25 BPA recommendations is listed with a status update and any supporting documentation if applicable, of the Company's implementation. In the instances where a recommendation did not require implementation but rather a response, the necessary information is provided.

a. Please provide a status update and example of the Company's implementation for each of the BPA recommendations.

<u>R.1 RCG recommends the Company retain and document higher cost and/or infeasible alternatives that were considered that could be provided to third parties during the regulatory process to aid in explaining the Company's decisions.</u>

The Company has implemented enhancements to its Solution Selection Form ("SSF") and Project Authorization Form ("PAF") to document its consideration of all alternatives, including alternatives determined to be higher cost or infeasible. Prior to this change in documentation, alternatives considered but not pursued were not consistently documented.

For **System Planning-initiated projects**, project alternatives are documented in the SSF. The project team and project initiator identify alternatives to resolve the grid needs and violations. These alternatives are included in the SSF and submitted to the Company's Solution Design Committee. Alternatives are sometimes identified but not considered because the alternatives are not practical or viable alternatives. These alternatives are now documented in the "Alternatives Considered But Not Pursued" section within the SSF. Attachment PUC TS 1-010(c)(1) is a copy of the Solution Selection Form (SSF) and accompanying guide.

For **Distribution Engineering-initiated projects,** the project team utilizes the PAF for all project authorizations and to capture project costs. Section 4 of the PAF includes documentation of alternative design considerations for any distribution project. Typically, an engineer will start their design using the least cost option. For example, Distribution Engineering will not spend effort to design and estimate a more-costly, underground solution if the overhead solution is sufficient because developing an underground solution estimate would be an inefficient use of resources when there is a sufficient and lesser-cost overhead solution. However, the Company's PAF now includes the identified underground solution (without cost estimates) in Section 4 of the PAF with an explanation for why the underground solution was not pursued (i.e., due to cost).

In addition, under Section 7, PSNH notes potential risks and methods of risk mitigation. Typically, a PAF will have attachments that include the design review and constructability review documentation to indicate to the New Hampshire Project Authorization Committee that all risks and alternatives were considered.

Attachment PUC TS 1-010(c)(2) provides a copy of the Project Authorization Form (PAF).

<u>R.2 Ensure that all three Eversource oversight functions Internal Audit, Enterprise Risk Management, and Capital Budgeting annually review an appropriate sample of capital projects over $250,000.</u>

The **Internal Audit Department** is planning an audit of the New Hampshire Distribution Capital Projects for 2024. The specific scope and objectives of the audit will be determined at the outset of the audit. Going forward, the annual audit plan will include an audit of New Hampshire distribution electric capital projects.

All capital projects in New Hampshire are reviewed monthly to ensure cash flow projections are accurate and overall physical construction and cost management of the project is on track. The monthly Capital Budget Review Committee (CBRC) meeting is facilitated by **Budgeting & Investment Planning** and is attended by all levels of PSNH management: System Operations, Station Operations, Field Operations, Transmission Operations, Investment Planning, Distribution Engineering, Station Engineering, and Project Management. Along with management, all identified stakeholders for the various projects attend the monthly meeting. Every project is discussed to review the following: forecasted monthly spending, authorization status including whether there is a potential need for additional funding, and the planned in-service date.

Enterprise Risk Management will perform a risk assessment of one distribution substation capital project and two distribution line projects annually beginning in 2024.

R.3 Introduce formal peer reviews into the overall CapEx project development early in the process to support enhanced decisions and training for design engineers.

Eversource Project Initiation

Projects are generally initiated, based on maintaining compliance with Eversource reliability design standards and practices, by one of the following groups within PSNH: Asset Management, System Planning, Distribution Engineering, or Interconnections. Examples of projects initiated by these group are as follows:

1) Asset Management- replacement of a transformer due to condition (i.e. health index), circuit breaker replacement due to parts obsolescence.

2) System Planning- addition or modification of a switching station, substation, distribution line, transmission line, transformer.

3) Distribution Engineering- reconductor of a distribution circuit, conversion to higher voltage level.

4) Interconnections- typically transmission-level interconnections are reviewed by an internal committee (Solution Design Committee) for consistency with the Company's engineering standards.

Each of these groups has its own peer review process as detailed below.

Asset Management Peer Review

In January 2022, Asset Management instituted a peer review process for all projects it initiates. In March 2024, the Asset Management group implemented changes in its project tracking Microsoft Access database to better document the peer review completion progress. This peer review process documents and supports the decision process of Asset Management engineers.

System Planning Peer Review

Beginning in May 2023, the System Planning organization established a series of monthly work plan meetings as part of the peer review process to discuss and approve System Planning-initiated capacity/reliability projects in New Hampshire early in the development process, before they go to the Solution Design Committee (SDC). The work plan meeting and similar predecessor meeting forums provide the opportunity for system planners to learn and gain experience with the role that System Planning has in developing alternatives to meet the system reliability needs. Planners also witness the interaction in relation to other engineering disciplines in the development of alternatives.

Distribution Engineering Peer Review

NH Distribution Engineering develops designs and plans for major distribution circuit improvement projects. These designs are typically initiated by the Circuit Owner (CO) who is an electrical engineer. Circuit upgrades are typically looked at based on reliability, overload condition or asset condition.

The CO typically develops a conceptual plan and reviews it with the manager. Once reviewed with the manager, the project is presented to a “challenge session.” A challenge session is essentially a peer review where the plan is reviewed by fellow engineers, the operations team, and other PSNH stakeholders. After the meeting, all feedback that contributes to a least cost solution is incorporated. Projects are once again reviewed prior to producing a detailed design for constructability review with construction operations.

Starting in 2024, NH Distribution Engineering is adding one more step to the review and planning process. An engineering design review will be done prior to the challenge session. This allows for a smaller, engineering-only review of the project’s solution, to ensure the team presents the best solution at the challenge session.

<u>Interconnection Peer Review</u>

The degree of peer review for a load interconnection request will vary depending on the size of the load. The review is performed by Distribution Engineering and Distribution System Planning. Typically load requests up to 1-2 MW are reviewed by Distribution Engineering and load requests over 2 MW are reviewed Distribution System Planning and may also include a review by Transmission System Planning if large enough (e.g. 10 MW).

Load interconnection requests submitted to Distribution Engineering that require system modifications receive peer reviews that include an engineering design review and challenge session, as mentioned above. The peer review is followed by further review by the NH Project Authorization Committee (NH PAC).

Load interconnection requests submitted to Distribution System Planning that require system modifications receive peer reviews that include a System Planning Work Plan meeting also mentioned above. The peer review is followed by further review by the Solution Design Committee (SDC) and the NH PAC.

<u>R.4 Enforce proper use of the term "Supplemental" consistent with APS-1 throughout the entire CapEx project process, including engineering.</u>

Through the BPA process, the Company became aware that, when explaining the various phases of project funding, the use of the term "supplement" or "supplemental funding" created confusion over the funding step that was being accomplished by the "supplemental" update. Thus, the Company clarifies use of the term "supplement" or "supplemental" below.

Historically, some large projects would receive funding based on a conceptual high-level project scope. This preliminary funding would allow the team to develop a design, engineering plan and detailed project scope to go out to bid and fully estimate the project. Because preliminary funding is granted on the basis of the conceptual design -- prior to completion of the detailed project design and receipt of contractor bids -- the conceptual estimate was based on limited information that needs to be supplemented through a detailed design phase. Therefore, another funding request would be required *prior to the start of construction* once all of the variables involved in undertaking the project are determined. This additional funding request was traditionally referred to as a "supplement" representing the final estimate of costs.

Supplemental funding requests were also used if unforeseen circumstances arose following the start of construction triggering the need for additional funding. This could result in multiple supplemental funding requests for a single project, which led the Department of Energy to believe that initial project estimates were not accurate, which was not the case.

In consultation with Rivers Consulting Group, PSNH renamed the final cost estimate calculated prior to bid as "the full funding authorization," which represents the initial, pre-construction estimate for all funding prior to construction. To clarify the purpose and significance of different cost estimates and the funding steps used by PSNH, in its documentation, the Company now refers to this as a "Revised – PAF pre-construction authorization." This designation is used for projects that are forecasted to be at least five percent more than the full funding authorization, when market conditions have resulted in vendor awards for labor or material that are higher than the amounts included in the approved full funding authorization. It should be noted that projects will still have supplements. These new designations are meant to provide clarity around the stages of funding estimation and authorization, but supplemental funding remains a tool used in the project development process.

These funding authorizations are performed in Power Plan, a comprehensive asset accounting software system that enables organizations to compile data and financial information into a single, highly detailed platform visible to all departments, and is approved by either the Eversource Project Approval Committee or the NH Project Approval Committee depending on the type of project. The Capital Approval Process is outlined in Attachment PUC TS 1-010(c)(3).

R.5 Develop easy-to-understand examples illustrating the before-and-after impact of DSPG 2020 system planning criteria changes on system performance (reliability and resiliency) for all PSNH customer classes (residential, commercial, and industrial). The examples also need to clearly illustrate how superseded standards ED-3002 and SYSPLAN-010 will be used in conjunction with DSPG 2020.

The document included as Attachment PUC TS 1-010(c)(4) provides a summary of Eversource's design criteria using visual examples to show comparisons between legacy design criteria contained within ED-3002 and SYSPLAN-010 versus today's Distribution System Planning Guide design criteria (DSPG 2020). The design criteria are applied to all Eversource facilities, each of which serves a mix of customer classes and therefore cannot be broken down by individual customer class (residential, commercial, and industrial) as requested in the recommendation.

A detailed comparison is included in table form as Attachment PUC TS 1-010(c)(5).

R.6 Develop a formal process to communicate the latest industry activities, including lessons-learned and technology advancements, between departments and potential external parties (other utilities and suppliers).

Substation & Transmission

There are various internal PSNH committees and subcommittees that have been established to review, share and address any relevant industry experience. Each area is responsible for investigating the details of advancing technology and whether it can be applied to the business. Please see Attachment PUC TS 1-010(c)(6) for the Company's internal Substation and Transmission System Operations Review Committee procedure for additional information.

An internal Substation and Transmission System Operations Review Committee

(S&TSORC) was established in 2006 and covers topics such as:

- Substation and Transmission system reliability and availability
- Substation and Transmission system disturbances and trends in disturbances
- Industry Operating Experience/Events (OE)
- Transmission Availability Data System (TADS)
- Bulk Electric System (BES) Cyber Asset patch management for Medium Impact assets
- Associated tactical and strategic corrective actions designed to maximize transmission system reliability, efficiency and effectiveness

Various other subcommittees were formed in 2006 to discuss areas such as:

- S&TSORC Disturbance Report Subcommittee (DRS)
- Substation Equipment Committee (SEC)
- Protection & Control and Test (PACT) Committee
- Transmission Operations Center Event Review Board (TOCERB)
- Transmission Line Equipment Committee (TLEC)
- BES Cyber Asset Patch Management Committee (BCAPMC)
- Operating Experience Subcommittee (OES)

Regarding sharing the Company's experiences with other utilities, PSNH participates in various industry conferences (such as Doble, IEEE, etc.) and is also a member of the North American Transmission Forum ("NATF") and this typically is where PSNH staff share broader experience with their industry peers.

Distribution

Identifying Industry or Equipment activities and issues:

1. Eversource has regularly scheduled meetings with National Grid and Con Edison to share information, as well as participate in other industry forums (North American Transmission Forum, Northeast UG Committee, etc.) to get industry experience and share information.

2. For equipment specific issues, PSNH receives technical service bulletins that review any operational or manufacturing issues.

3. The Company participates in industry technology conferences such as IEEE and Distributech where new technology trends for field equipment and software are evaluated with vendors and other utilities.

4. The Company also participates in industry committees organized by the Association of Edison Illuminating Companies ("AEIC") on various topics such as distributed energy resources and power delivery.

5. For the Company's operational technology, representatives participate in user groups and customer advisory boards to collaborate with the software vendor and other utilities in the development of future capabilities.

Processes for communicating internal within the Eversource service companies:

1. Share critical information through a supervisor briefing sheet or a technical service bulletin published to the engineering and operations teams. See Attachment PUC TS 1-010(c)(7) for an example of a technical service bulletin.

2. Standards Engineering holds a monthly standard governance committee meeting where the committee reviews/communicates any equipment issues or industry lessons learned. This committee has representation from the following internal departments: Standards Engineering, Protection and Control Engineering, Distribution Engineering, Substation Engineering, Grid Modernization Engineering, Telecomm Engineering, Safety, Procurement, Operations, and Field Training.

3. In addition, materials from industry committees and conferences are shared and reviewed internally with multiple engineering groups.

Procurement

On the supply chain side, Procurement has a formal Supplier Relationship Management (SRM) program that involves quarterly or annual meetings with some of the Company's key suppliers (based on spend, criticality, and transactional volume). These meetings are held with suppliers and key business partners to review all vendor interactions, metrics, etc. to improve vendor performance as well as identify areas of improvement for Eversource.

There are two other key Procurement industry initiatives that Eversource is directly involved with that collaborate closely with other utilities and vendors. EEI has a Chief Procurement Officer (CPO) group that meets monthly to discuss and address supply chain constraints across the industry and collaborates on initiatives aimed at improving the flow and reliability of materials and equipment. The Vice President of Supply Chain participates in this initiative.

Eversource is also a key member of Electric Utility Industry Sustainable Supply Chain Alliance (EUISSCA) that is an organization focused on driving sustainability across the utility supply chain. There are well over 20 utility partners in this organization, as well as a group created called "Supplier Affiliate Members" that brought suppliers into EUISSCA to foster more direct interaction with suppliers.

R.7 Include person hours on all planned project work orders to support crew performance management.

Including person hours is not always possible because PSNH uses a mix of internal and external resources. However, the Company uses other tools to ensure crew performance management where appropriate.

When PSNH uses external resources, the Company requests that the contractor-bidders provide lump sum pricing or unit pricing which allows the Company to have a means of comparing contractor bids inclusive of labor hours. By using a competitive bid process and holding the successful contractor to their bid price, the Company ensures crew performance because the contractor has an incentive to stay within its contract price.

Internal PSNH resources are used on other work orders or projects, but travel time can vary greatly and create a disparity in costs depending on a customer's location, and therefore is not accounted for in the estimating tool so that the tool can provide standardized cost calculations for all customers. For internal resources, Eversource monitors performance based on dollars spent, and accounting for costs this way identifies if work is occurring on schedule.

The Company notes that, even with systems in place to ensure performance, there are circumstances where additional labor resources may be necessary. Costs for distribution system work are contingent upon many variables that need to be monitored, as they can impact costs significantly. Examples include soil conditions, traffic needs, material availability and quality.

In addition, the Company has a commitment to respond to outages before performing any other distribution system project work. If a crew is working on a line extension and a vehicle hits a pole causing an outage, the crew must respond to the vehicle accident as quickly as possible to restore service and ensure safety to the public at the accident scene. This system of prioritization can delay line extension work but is essential for public safety and reliable service for all customers.

R.8 Develop and test (as a joint effort between System Planning and Distribution Engineering) detailed Synergi feeder models, taking full advantage of System Planning's familiarity with Synergi to facilitate the process.

A standard process for feeder development in Synergi has been implemented pursuant to this recommendation. Please reference Attachment PUC TS 1-010(c)(8) ("Final version - Synergi BASE model harmonization compromise DER Planning and DSP MA.pdf"). This process has been shared with model developers. Feeder models are developed and verified in collaboration with Distribution Engineering. The System Planning Modeling group has developed a process to identify and track Synergi model and data issues which are then resolved in collaboration with data and information owners, including Distribution Engineering.

Please refer to Attachment PUC TS 1-010(c)(9) and Attachment PUC TS 1-010(c)(10) for "Data defect feedback" and "CED information IO", respectively.

The Data defect feedback flow diagram describes the mechanism, by which data defects are being identified, logged, and submitted to data source owners. The system providing data to Synergi Electric contains data defects, which are identified by the modeling engineers. The modeling engineers are following the process for reporting data defects according to the diagram.

The Central Engineering Database (CED) information input-output (IO) flow diagram describes the data entities involved in the Power flow model build process. The shapes containing a description on the inside are databases or database tables. The arrows connecting different shapes represent data connections and the direction in which the data flows. The Central Engineering Database (CED) and the Consolidated GIS Viewer (GIS) are the main systems in this diagram. IO stands for "Input-Output", describing the linear flows in this diagram.

R.9 Perform an in-depth/rigorous analysis of the data-checking and conversion process for new software platforms (e.g., DistriView to Synergi data sets) independent of the Grid Mod group's conversion verification process to ensure that data continuity and integrity are maintained throughout.

As the Company transitioned to the new distribution analysis software tool, Synergi Electric, the legacy DristriView data sets were not transferred to Synergi. Both tools pulled data from centralized sources, such as GIS, to build their models. As Synergi was rolled out, the Synergi forge process was implemented. The forge process is an automated workflow that synthesizes data from various underlying sources and performs data transformation and translation to meet the input requirements for Synergi Electric. The Company has provided its modeling and data quality management process for the Synergi models as part of its efforts to address recommendation R.8 of the Business Process Audit.

Comparing the two software platform models (DistriView and Synergi) is not practicable, as no baseline exists to indicate which platform is more accurate. The preferred approach to managing data quality in such systems is data control of the source systems. Current automation efforts are underway to focus on automatically identifying some of the most impactful data source issues manifested in Synergi Electric and automating the information feedback to the data source owners to strengthen control over source data. In addition, a tracking system has been established to allow users to report data and modeling issues to a centralized modeling team which was recently stood up to manage and maintain the integrity of system models. The team will address issues in collaboration with data owners.

R.10 Develop detailed documentation to maintain data integrity as data conversions are made from one software platform to another, e.g., DistriView to Synergi, Storms to Maximo. This is especially true for Synergi, where individual phase models for distribution circuits are being developed, i.e., converting from 3-phase balanced distribution line models to 1-phase unbalanced distribution line models.

The Company determines how best to maintain data integrity as data conversions are made from one software platform to another, based on the specific project need. As detailed below, implementation of new systems does not always result in data conversions. However, even where new systems do not result in data conversion the Company has data quality processes in place.

DistriView to Synergi

Please refer to BPA recommendation R.9. The Company did not convert DistriView models to Synergi. Rather, when Synergi was rolled out, a new forge process was developed that pulls model data from source systems. Data quality is managed through the model and the data-quality process is outlined in BPA Recommendation R.9.

Storms to Maximo

For the Maximo implementation there was no conversion effort or interface medium with Storms. The work was finished out in Storms as applicable and the Company created a header record in the Maximo system to let users know that the work was housed in the Storms system. This ensured data integrity was maintained because the actual data stayed in Storms until completion of the work. When all work was completed in Storms, the Storms system was closed out and converted to read only.

Maximo communicates with multiple systems using an interface medium to ensure the data is transferred correctly between systems. During the implementation, a testing period occurred with System Acceptance Testing (SAT) and User Acceptance Testing (UAT). These testing events verify the data between each integration step that occurs to ensure data is correct and to build confidence between the systems. Eversource also notes the system of record; for example, though Maximo has financials from Power Plant, Power Plant is the system of record for all financials on projects and Work Orders.

Currently, Eversource has developed a group, Technology Business Operations, which manages Maximo and other Work Order Lifecycle software tools.

R.11 Investigate the potential benefits of retro-filling power transformers with the latest technology insulating fluids, e.g., extending transformer life (without compromising reliability) and deferring capital investments. Include guidelines for identifying candidate transformers.

There appears to be a growing interest in alternative fluids in the electric power industry that the Company is monitoring and considering, as appropriate. However, the industry is not poised to adopt these alternatives at this time. As such, the Company can provide the following for informational purposes only to offer the DOE insight into the relevant considerations around this issue. Actual use of alternative fluids and retro-filling would have to be analyzed on a case-by-case basis.

These alternative fluids are mostly natural and synthetic esters. In addition to the environmental benefits there is a lower flammability benefit (higher fire point). Whether this will translate to wider acceptance in the coming years is uncertain. Major change won't happen quickly since manufacturers need time for research and development to determine best applications and obtain more in-service operating experience. There seems to be selective acceptance of alternative fluids in transformers but this has been seen more with distribution transformers, not necessarily with station power transformers.

The first element on which to focus regarding switching away from mineral oil might be with units in or close to flammable equipment or in buildings. Another possible early element for this transition could be for those transformers that are close to waterways or other environmentally sensitive areas where an oil spill would be a risk that could be mitigated with a more environmentally friendly or biodegradable alternative.

Focus may be more effectively directed on getting alternative fluids in new transformers rather than retro-filling existing units. The dielectric clearances and thermal efficiencies change for the unit if the dielectric medium is changed, so retro-filling needs to be very carefully examined on a case-by-case basis to determine if it is prudent to be further pursued. A potential retro-fill option would be evaluating a unit that is fairly lightly loaded and observing its operation for a number of years to ensure continued successful operation.

It should be noted that the cost of a new transformer with alternative fluids is higher than with currently used fluids. Added cost, coupled with the fact that there is limited in-service experience, creates a barrier for widespread adoption, at least in the near term. One further salient factor to consider is that the dissolved gas analysis ("DGA") for ester-based fluids is different than traditional fluids; as such, interpretation and analysis of gas formation to determine health of the transformer is not clearly understood at this point, which is an impediment to widespread adoption of this practice near term.

R.12 More clearly explain and illustrate with examples why the best overall solution alternatives are not always the least-cost solution alternatives. It is not sufficient to simply state that all criteria violations have been resolved. In addition, consistently document all alternatives considered in the formal project paperwork. Include a formal statement on NWA solution considerations (even if the statement says NWA solutions were not applicable) and reasons why.

There are three general categories of projects: (1) capacity; (2) reliability; and (3) asset condition. The Company has made enhancements to its alternatives analysis for each of these categories as described below. The Company also applies its NWA framework to all projects including application of an initial screening to determine which projects are appropriate for NWA analysis. Pursuant to the NWA framework, an NWA analysis is only performed for projects that meet the following threshold criteria: (1) the costs associated with the traditional solution are greater than $3 million; (2) the project has a planning horizon of greater than three years; and (3) the project is not being undertaken due to an asset or age condition. As discussed below, the Company's enhanced alternatives analysis includes noting for projects that are not selected for NWA analysis, the reason that a project failed to satisfy one or more of these threshold criteria.

System Planning

The Company's System Planning group develops projects to address bulk distribution system capacity and reliability needs. System Planning enhanced the official Solution Selection Form (SSF) template for System Planning projects that go to the Solution Design Committee (SDC). Enhancements include clear documentation of the NWA pre-screening assessment (i.e., whether the project meets the NWA Framework threshold criteria), or a more in-depth NWA alternative solution if applicable, as prescribed in the DSPG. The template also includes an alternatives summary section that notes the alternatives and the reasoning for selecting the preferred alternative over other alternatives. The template notes that when the preferred solution is not the lowest cost alternative, the reasoning for why it is selected must be included in the summary. For example, the preferred solution might have strategic value that the other alternative(s) do not have. This strategic value will be included in the summary.

The SSF template enhanced for System Planning that is described above was distributed to all Company personnel in System Planning in March 2024. The enhanced SSF template has been used for all projects initiated after March 2024.

Distribution Engineering

The Distribution Engineering group develops projects to address reliability issues on the distribution feeder system. As part of the project documentation for these projects, an NWA screening is performed for projects that meet the threshold criteria, as well as documenting other considerations to address the system need. Through the documentation process, using the PAF, Distribution Engineering will provide an explanation of why the best overall solution alternatives may not be the least-cost solution alternative by providing more of an explanation than just "all criteria violations have been resolved". In addition, all alternatives considered will be documented in the PAF, including a statement on NWA solution considerations, even if not applicable, and associated reasoning.

Asset Management

The Company's Asset Management group develops projects to address asset condition or age. Pursuant to the Company's planning standards and NWA framework, projects related to asset condition and safety issues are not considered for NWA solutions. The Company includes an explanation for any alternatives considered or an explanation for why there are no reasonable alternatives. For example, the Company would not consider an NWA alternative for a failing asset because there would be no practical application of an NWA.

R.13 Compare how the traditional solution alternatives are developed and priced against how NWA solution alternatives are developed and priced. Identify areas that disadvantage NWA solutions, e.g., how projected O&M costs are treated. Document key drivers that contribute to the cost differences between traditional and NWA solutions.

For System Planning projects, the System Planning engineer performs a pre-screening assessment that determines whether an NWA analysis is applicable. For projects that meet the pre-screening requirements, the System Planning engineer assesses the general list of NWA options available and records the assessment in the alternatives section of the System Planning SSF. The System Planning engineer would determine the applicable NWA solution and assess that solution and the traditional solution using the NWA screening tool that calculates the Benefit Cost Ratio (BCR) of both the traditional and NWA solutions. The tool includes estimated NWA per unit costs, which are based on previous projects, estimates and industry data. The resultant BCR identifies the most cost-effective, technically viable project alternative. The System Planning engineer documents the NWA and the above assessments in the SSF.

In detail, during the NWA screening process the traditional solution's cost is developed by engineering and estimating. These costs are compared to standardized NWA costs where the Company utilizes the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) database. The cost of solutions are compared on the basis of cumulative net present value revenue requirements impact; this means that all revenue requirements incurred through either the traditional or NWA solution, including O&M costs, are calculated to present value. If the NWA solution is only able to defer, as opposed to replace, a traditional project, the value of deferral of the cumulative net present value revenue requirements is used.

The key difference in the costs is the scalability of each solution set, as traditional solutions and NWA solutions' costs are impacted very differently as the scale of the solution changes:

- Traditional upgrades come in standardized sizes, such as 62.5 MVA transformers, and cannot be provided in incremental units. Therefore, if the need is small, upgrades tend to be more expensive per MW of need, and get cheaper per MW the larger the need is.

- NWA solutions often scale more or less linearly with need. As a result, small solutions can be deployed relatively cheaply, while large solutions are extremely expensive.

Therefore, NWAs are typically most cost effective where the needs are relatively small and a comparable traditional solution cost would be large. This is why one of the pre-screening criteria the Company uses for NWA solutions is that the traditional solution has an estimated cost of less than $3 million.

Further, NWAs have a distinct disadvantage when they intend to defer traditional solutions for multiple decades as their life expectancy is in almost all cases lower than those of traditional solutions, requiring constant repowering and new equipment to maintain, as opposed to traditional solutions that need relatively less ongoing maintenance work to sustain over the same period of time. In addition, some of the NWA assets require higher O&M costs, such as maintenance of their own power supply, which drags down any BCR.

R.14 Develop and conduct in-house training programs for New Hampshire DER hosting map development engineers. Lessons learned from Eversource CT, and MA should be integral parts of this training.

A training session was conducted with New Hampshire Synergi Electric users from March 11 through March 13, 2024. The training topics included standardized model development steps, data sourcing, methods and procedures within Synergi Electric and sources of documentation. The goal of aligning best practices with CT and MA, based Synergi Electric users has been successfully achieved because lessons learned from these jurisdictions were incorporated into the training and training materials.

Attachments PUC TS 1-010(c)(11)-(13) provide a copy of the training materials offered.

- Attachment PUC TS 1-010(c)(11) – Model Build Steps

- Attachment PUC TS 1-010(c)(12) – Central Engineering Database (CED) Information Input-Output (IO)
- Attachment PUC TS 1-010(c)(13) – Base Model Development Harmonization

R.15 Continue to investigate Conservation Voltage Reduction (CVR) potential energy/demand savings for PSNH, given the relatively high portion of residential system load --- 44% kWh residential sales: 50% kW residential peak demand.

Eversource continues to investigate Conservation Voltage Reduction, potential energy and demand savings for PSNH by planning and implementing the control room software capabilities within the Company's Distribution Management System ("DMS") and by investing in voltage control field device upgrades (voltage regulators, capacitor banks, transformer load tap changer controls) that will allow the DMS to optimize the voltage and reactive power on the distribution system. The Company is also able to leverage the experience of its Massachusetts electric distribution company affiliate.

The Massachusetts electric distribution companies, including the Company's affiliate, have been implementing grid modernization plans and conducting associated evaluations. One component of these evaluations was the 2022 study of volt-var optimization on select feeders. The results of this study can be found in "Massachusetts Grid Modernization Program Year 2022 Evaluation Report: Volt-Var Optimization" by Massachusetts Electric Distribution Companies assembled by Guidehouse Inc, and provided as Attachment PUC TS 1-010(c)(14).

As discussed in the evaluation report within Eversource's Massachusetts service territory select feeders saw the implementation of full SCADA control of voltage regulation (line regulators and transformer LTCs) and line capacitors. Based on the data reported in the performance metrics between Spring 2022 and Fall/Winter 2022, an overall system voltage reduction of 1.24 +/- 0.01% was identified. This resulted in a peak demand reduction of -0.7 +/- 0.46%.

Reviewing historical system peak demands for PSNH retail customers (excludes load delivered to Unitil, New Hampshire Electric Cooperative, and municipal electric departments), PSNH would expect to see a reduction of 4 MW to 19.5 MW across its New Hampshire service territory. While the areas in Massachusetts that were sampled are similar to areas in PSNH's New Hampshire service territory, the distribution voltages operated in Massachusetts are comparable to New Hampshire's 4.16 kV and 12.47 kV distribution systems. It is uncertain what impact operating at a higher system voltage (34.5 kV) would have on this peak load reduction assumption. In addition, before the Massachusetts results can be replicated, the Company also needs to implement the SCADA control of voltage and reactive power equipment on the system to enable the centralized control logic. This would involve adding communications and electric infrastructure.

<u>R.16 Conduct a protection and coordination study in conjunction with System Planning at the distribution circuit level to better understand and anticipate how 2-way power flows can be safely accommodated.</u>

As part of the interconnection process, PSNH already conducts protection and coordination studies in conjunction with System Planning, Protection & Control, and Distribution Engineering at the distribution circuit level. The Company conducts these studies using the Synergi System Model, which identifies how two-way power flows can be safely accommodated.

The PSNH DER interconnection process and evaluation includes a review of the distribution system with proposed DER to determine the direction of the power flow and potential impact to PSNH's equipment. For example, line voltage regulators in the path between the DER point of interconnection and the substation are reviewed to determine if the equipment is uni-directional or bi-directional. Protection and coordination review and study are also performed as needed in collaboration with Protection & Control and Distribution Engineering. These evaluations are documented in the associated DER system impact study for each project requiring such a study.

The documents used to conduct the evaluation are contained in the Eversource Distribution System Engineering Manual (DSEM) under Distributed Generation Policies. The DSEM is provided as Attachment PUC TS 1-010(c)(15). For example, DSEM 19.012, "Transformer Reverse Power Capability", is used to assess reverse power capability of substation transformers. The Company also uses its Eversource Distributed Energy Resources Planning Guide (DER-PG 2022 draft) provided as. Attachment PUC TS 1-010(c)(16).

<u>R.17 Take more aggressive actions to correct chronic problem feeders by implementing one or more of the following:</u>

<u>• Reduce COSAIDI targets or other reliability targets to encourage more aggressive distribution automation and sectionalizing schemes; and</u>

<u>• Find locations where alternate feeds can be feasibly constructed for long radial circuits, i.e., create circuit loops, not just segmented customer groups; and</u>

<u>• Apply localized NWA solution options, where suitable, when looping feeders is not a feasible alternative and the solution exceeds the NWA threshold. Subsequent revisions to the NWA Framework may be required.</u>

- The Company does prioritize COSAIDI target with distribution sectionalizing schemes. The Company has implemented over 2,000 distribution "Trip-savers" to reduce momentary faults. Eversource also evaluates coordination possibilities on circuits and either upgrades the circuits or converts them to three phase where possible. This allows for smaller pocket groups during an outage.

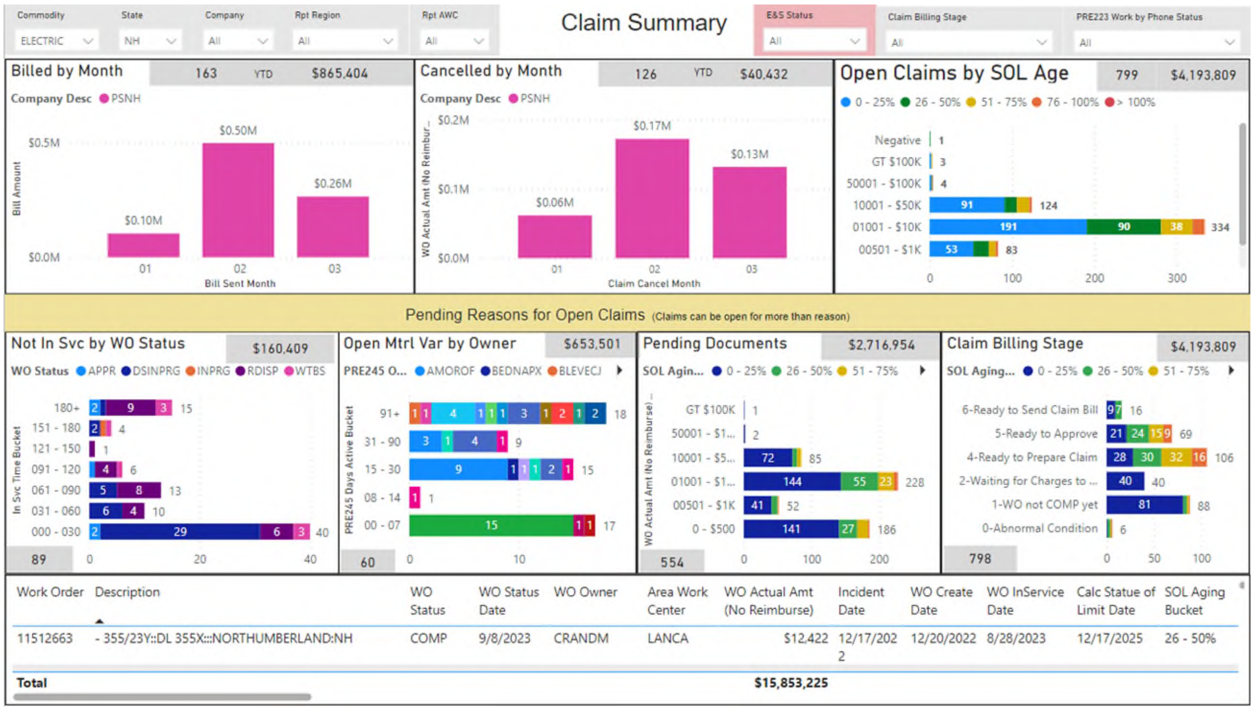
- Automated loops and ties to nearby circuits are reliability solutions that the Company typically evaluates as part of its reliability programs. The Company will continue to identify locations where alternate feeds are feasible, cost-effective and beneficial, and evaluate automated loops as part of its reliability improvement strategies.

- The Company's existing NWA framework can evaluate the cost competitiveness of NWA solutions versus traditional wires solutions, such as loop feeds, for project needs that meet the suitability criteria. The NWA model is revised annually to ensure alignment with Company planning standards and requirements. The Company agrees that utility-owned and operated BESS-based NWA could be a potential solution for the referenced reliability issues and has processes and tools in place to assess its technical and economic viability.

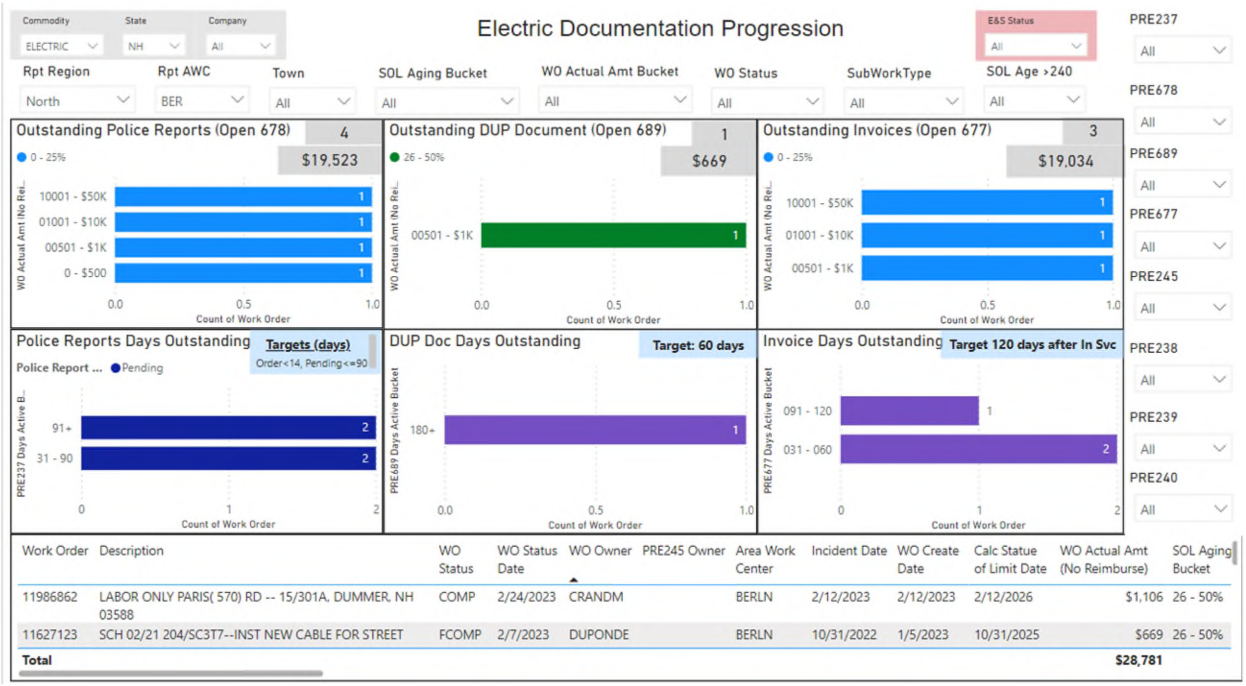
R.18 PSNH should develop a formal method to track the status of third-party claims in process but not yet completed at the operating center level.

The Company has implemented a new dashboard to track the status of third-party claims. The dashboard informs Company leadership of the number of claims billed or cancelled the demographics (accrued charges and statute of limitation age) for the claim, and the reason for any outstanding claims. The dashboard also enables users to access greater detail regarding the claim and take action on specific claims that need attention.

Below, the Summary tab of the dashboard is reproduced, which opens further detailed pages for any of the categories included on the summary page:



See below for an example of drilling down to a particular area work center:



R.19 PSNH should create an accurate job description for the Administrator position that reflects the importance of the third-party claim's preparation process.

Please see Attachment PUC TS 1-010(c)(17) for the Administrator positions. Not all specific duties such as double pole processing, property damage claims, police detail processing, ARCO's updates, etc., are listed as primary responsibilities within job descriptions, but this in no way lessens the importance of any of these, and any other necessary and required tasks, and the Company expects exemplary execution of all job responsibilities and tasks. There is no specific reference to the third-party claim's preparation process because position descriptions are generally designed to focus on broader categories of responsibility. Additionally, job description changes require contractual agreement by the union which can become a negotiation item resulting in a need to modify compensation.

However, the Company now provides the following supplemental information within the job description to address DOE's recommendation:

"Note: This description does not describe all of the responsibilities inherent in this job. It provides as much detail as necessary to distinguish this job from all other jobs. In addition, the requirements

list are not all inclusive. Management has the right to make determinations based upon individual circumstances."

R.20 PSNH should revise the third-party claims process to have the Claims group review incidents where no responsible party is identified or when the operating center management has closed an incident without generating a claim.

In 2023, PSNH implemented a quarterly review of third-party claims where no responsible negligent party could be identified. The Company established a threshold dollar amount of $10,000 to trigger a review for these types of claims. The Claims group and the administrative staff preparing these matters now meet quarterly and review each cancelled claim to confirm there was no viable negligent party to pursue.

R.21 PSNH should develop a flowchart and process narrative to define and illustrate the entire third-party claim process in one document.

Please see Attachment PUC TS 1-010(c)(18) for the flowchart and the process narrative applicable to the third-party claim process.

R.22 PSNH should correct the software which improperly allocates reimbursements to Account 107 instead of Account 108.

The correction to the Maximo software issue that previously improperly allocated reimbursements to FERC Account 107 instead of FERC Account 108 was remediated in Maximo on July 29, 2022.

R.23 If PSNH cannot complete a response to a data request and transmit the data response within ten business days, an estimated completion date should be formally transmitted by the tenth business day.

The Company has processes in place to ensure that discovery is completed timely and that any delays are communicated together with an estimated date of completion.

Members of the Company's Regulatory team meet with legal counsel, docket witnesses and internal supporting subject matter experts (SME's) upon receiving the data requests to discuss each data request. These discussions are to ensure that the Company understands the data requests, identifies the appropriate witness and supporting SMEs to gather the information and to determine the feasibility of providing the information within the required ten business days. These efforts are to identify early on whether additional time will be necessary to respond to the request. Should the witness or supporting staff identify the need, or even the potential need for additional time, the Company's legal counsel will reach out to discuss it with the DOE as soon as the need for more time is discovered and provide a reasonable response date for that specific question.

Occasionally, the need for more time will arise unexpectedly due to unanticipated complications in data collection efforts or circumstances outside the Company's control, such as storm restoration efforts. The Company is taking all measures to ensure this is the exception, and not the rule. In the event that a need for additional time is not discovered until the due date on the tenth day, counsel for Eversource will reach out to the issuing party to provide an explanation as to the circumstances and provide an estimate of the additional time needed.

R.24 In its data responses, PSNH should highlight its ongoing and planned responses to issues and the impact of third parties' actions, rather than embedding the issue within the data.

It is the Company's understanding that this recommendation is related to an issue that was discovered in the data response associated with the third-party damage claims during the audit. The Company will continue to do its best to exercise due diligence in gathering response information, execute thorough review of all relevant information, and provide fulsome, explicit, and transparent responses to future data requests. The Company will also ensure that issues are clearly communicated as part of the response and not embedded in the responsive data.

R.25 To facilitate and clarify data requests and responses, PSNH and DOE should consider adding technical conferences before and after data requests are requested and responded to.

In response to the audit recommendation, the Company has been mindful to foster and maintain timely communications with the DOE throughout its docketed proceedings, including during discovery both before and after data requests are issued. After receiving the DOE's data requests, the Company evaluates the requests for information with legal counsel, the witnesses and internal supporting subject matter experts. In circumstances where there may be different interpretations of a question or ambiguity as to what the DOE is seeking, the Company's legal counsel seeks clarification from DOE counsel before the subject matter experts begin developing their response to the question.

Thus far, in the majority of cases, DOE's data requests have been clear and have not necessitated a technical conference for clarification prior to responding, but if one is needed the Company will reach out to arrange one.

It is common practice to hold a technical session following submission of responses to party data requests to discuss the responses, provide additional context, and clarify responses as needed, including taking any follow-up data requests, to ensure that all participating parties have the information they are seeking and the relevant objectives of the docket are progressing.

b. **Please explain what changes were implemented as part of this Rate Case filing that reflects Eversource's efforts to improve communication and clarity of information presented which was a central theme of the BPA Report.**

The Company has taken several actions since the last rate case and as a result of the Business Process Audit to continuously improve communications with the DOE staff. Examples of these efforts include but are not limited to:

Pre-Rate Case Filing

DOE Educational Sessions: As a direct result of feedback received throughout the audit process, the Company conducted a series of education sessions with DOE staff to provide detailed context regarding the region's electrical grid, the Company's electric system, and different components of the necessary infrastructure needed to ensure safe and reliable power to customers. The series included multiple in-person meetings over the course of five months, with detailed presentations provided by Company leadership and subject matter experts. The presentations provided pictures, graphics, charts, definitions and explanations of industry and business processes, practices, equipment and terminology. The main objective of the series was to communicate in a more effective way through an informal setting allowing for two-way conversation and engagement between the Company and DOE and to use this opportunity as a way to help better explain what it is we do on a daily basis and how our system works.

Regional Overview – June 2022

The Company provided a broad view of (1) New England's Current and Future State of the Transmission Grid, (2) New England climate impacts, drilling down into (3) New Hampshire Distribution in its Current State as it related to demand, reliability performance and substation equipment, followed by (4) New Hampshire's Distribution looking into the Future State related to demand, substation capacity, reliability and resiliency and transmission.

NH System Operations Overview – July 2022

The Company reviewed the NH Control Rooms, the Transmission System, Control Centers, Distribution System, System Reliability, System Operations Center and the Troubleshooter Line department.

Emergency Preparedness Overview– July 2022

The Company covered the Emergency Management "Life Cycle" from Mitigation, Preparedness, Response to Recovery, the Incident Command Structure, the All Hazards Emergency Response Plan, the Emergency Response Plan (ERP), the Incident Management Team, the Incident Command Center, Readiness Conditions, ERP

Declaration Table, Mutual Assistance, Logistics and Staging Areas and Customer Communications.

Transmission System Overview – August 2022

The Company provided a presentation exploring: how transmission fits in the grid, the role Transmission plays for our customers, the equipment attached to a transmission structure, types of poles, varying voltages, pole materials, vegetation requirements, underground transmission, inspections, apprenticeship program, sequence of construction, large transmission projects in NH, outreach efforts.

Substations Overview – September 2022

Provided an overview of how substations fit into the electric system, station layouts, power paths through the station, major equipment in a substation, with explanations and pictures of types of switches, circuit breakers, power transformers, instrument transformers, capacitor banks, sync condensers, control house and batteries. The session also covered system automation, protection and controls and various types of substations on the Eversource system. It also covered animal protection, environmental mitigations, security and the skilled workforce needed to maintain and operate the stations.

Distribution System Overview – September 2022

This session focused on basic electric concepts, and provided explanations with pictures of distribution poles and equipment, voltages, insulators, cross arms, cable types, pole types, pole materials, guying, protection devices, SCADA controlled devices, transformers, step transformers, capacitor banks and voltage regulators, grounding, pad mounted transformers and switchgear, underground networks, redundancy and automation. It also provided an overview of the Mobile Asset Assessment Vehicle (MAAV) which conducts inspection scans for stray voltage. We also discussed Distribution projects happening along the roadside as well as in right-of-ways, off the road along with software used by field crews when working on the system.

Field Visit – October 2022

Company leadership and subject matter experts spent an entire day in the field with the DOE, taking commissioners and staff to various sites throughout the state to show them different pole types including concrete poles, class I vs class II vs class III poles. The group saw a Spacer Cable Installation project, pole replacements projects, one of which was transitioning from wood to steel poles, substation visits to Scobie Pond Substation in Londonderry where there is a transmission and distribution substation yard to show the control houses, equipment and security infrastructure along with Farmwood Substation in Concord where there's a Synchronous Condenser.

It is the Company's understanding based on feedback directly from the Department, the DOE found these sessions informative and helpful, especially given the amount of newer staff members. As a result, the Eversource team explored a series of 2023 Educational Sessions around Energy Efficiency, Metering, Solar Interconnections, and Vegetation Management and were open to other topics that may be of interest to the DOE staff. Although another round of Educational Sessions were proposed to the DOE, the DOE requested that we revisit scheduling the sessions until a later date given time constraints on schedules. The Company looks forward to continued opportunities of working with the DOE in this capacity.

Additional Information Sessions:

Supply Chain Challenges - April 2022

Rapid Pole Demonstration – September 2023

PowerClerk Portal for Solar Interconnection Applications– October 2023

PowerClerk Demonstration – December 2023

Supply Chain Challenges Update – February 2024

Stray Voltage Scanning Truck Presentation/Demonstration – April 2024

Control Room Observations – May 2024

DOE Enforcement Division staff received a presentation from the Director of Electric System Operations followed by tours and observations of controllers in both the System Operations Center (SOC) for Distribution and Electric System Control Center (ESCC) for Transmission to better understand the job functions of the staff operating the system from the control rooms on a daily basis.

Trouble Shooter Observations – August 2024

An Eversource troubleshooter guided staff from the DOE Enforcement Division throughout a day in the field as a troubleshooter, to help provide a better understanding of the type of jobs and daily trouble calls that are part of a typical trouble shooter's daily work.

Investigation Participation in IR 22-048: PUC Investigation of Step Adjustment Methodology and Process. The Company was an active participant in the Commission's proceeding to better understand the step adjustment methodology and process by providing comprehensive information to the Commission and other parties to the investigation around the history of step adjustments, how to effectively utilize utility and regulatory resources when reviewing and adjudicating step adjustments and full rate cases, as well as timeframes and methodologies for formulating step adjustment petitions.

In addition, the Company provided thorough responses for solutions on how to reduce or eliminate the need for annual step adjustments or decrease frequency of rate filings. The Company also helped to inform the Commission and the parties about the relationship and differences between a distribution rate case, a step adjustment program and a Company's integrated resource planning process. Based on direct positive feedback received by Commission staff and other parties specifically regarding the way the Company articulated its responses, the Company utilizes many of the statements made throughout other dockets and proceedings including the present DE 24-070.

Capital Additions Template Revisions: As stated above, the main objective of the Business Process Audit process was to address DOE's concerns regarding the Company's documentation of certain capital projects involving their planning, budgeting and management. To help address this concern, the Company was to develop a regulatory review template to guide the development and production of capital project documentation generated through the Company's capital authorization process. The purpose of the regulatory review template was to facilitate the Commission's review of future requests of the Company to recover the costs of capital investments.

Based on direct feedback from RCG throughout the audit process, the Company took an extensive look at its capital additions template and worked with RCG on ways it could be improved. All terminology used in the template was reviewed, terms were adjusted to more accurately indicate the fields they represent, unnecessary or confusing fields were removed, and variance rationales were included for specific projects to ensure a clear explanation of why a project was over or under budget by more or less than 20% along with other various improvements. Following these updates, the Company reached out to the Department in May and December of 2023 to gain their feedback on the revised Capital Additions template. However, the Company was encouraged by the Department to simply incorporate the feedback based upon the Business Process Audit. The DOE did not provide any additional feedback to the template.

Capital Project Documentation Packages: One main addition the Company included in the rate case filing as a direct result of the BPA is comprehensive documentation of all capital projects. The Company included as part of its filing on June 11, 2024, a standard project documentation package for each project that includes the newly revised Capital Additions template, along with each Project Authorization Form ("PAF), and Supplemental Authorization Form, if necessary, and a Closing Report detailing the project costs, as applicable. Rather than waiting for the Department or other parties to request this material, the Company provided the materials by including a project listing and organized the respective documentation in accordance with that listing, in the spirit of full transparency, for each project.

In addition, consistent with the BPA Recommendations, the Company updated the Solution Selection Form (SSF) and the Project Authorization Form (PAF) to better demonstrate and document the breadth of alternatives that were considered (including NWA's) and why the lowest cost alternative may not have been adopted, for projects on a going forward basis beginning in early 2024.

Rate Case Meetings Prior to and After Filing

The Company understands the importance of communication and continuous enhancements regarding clarity of information. In advance of the rate case filing, initial discussions took place to coordinate a meeting between the Company and the DOE to discuss the anticipated rate case filing in June. The Company was able to meet with the DOE Commissioners in May, DOE staff in June (shortly following our filing), and OCA staff in early July to provide the parties with a Rate Case Overview presentation, allowing for an informal opportunity to answer initial questions and have informative discussions about the filing.

<u>Rate Case Filing</u>

Testimony

As the team developed the rate case testimony, there were also discussions of the need for clear communication in particular for components of the case that are particularly complicated to explain such as Performance Based Rate Making, a type of rate making unlike that which we have now. The testimony was developed with a focus on clear, concise communications and reviewed in the same manner.

Distribution Solutions Plan

In its initial rate filing, the Company developed and submitted the first ever Distribution Solutions Plan (DSP) to more clearly explain the planning process for the distribution system and the proposed investments in this case. The DSP provides a roadmap of how Eversource conducts their planning process for major capital projects and lays out an overview of key areas of investment that the Company needs to undertake to continue to deliver safe and reliable electric service to customers. The DSP allows the parties to have a comprehensive story with a clear overview that also goes into more detail as needed, explaining why the Company needs the level of investment being requested.

The DSP starts with the current state of the distribution system along with the challenges that must be addressed, down to the region. Given those challenges the plan moves into how the Company's planning processes to address those challenges by identifying various processes, assessments, standards, criteria and tools that aid in that planning process. The DSP then discusses the five- and ten-year demand forecasts and moves to the planning solutions to address the challenges the Company sees the distribution system facing. In addition, the DSP describes the capital plan and the customer benefits that will be achieved based on that five-year investment plan.

While the plan methodically lays out the process of how the Company plans and arrives at the investment amounts needed for the distribution system, a key take-away from the audit was directly incorporated by ensuring the industry terminology and acronyms were included to sufficiently define the terms in an understandable format for all parties reading the document. This resource can be found in the first 7 pages of the DSP appendix. *(Reference DSP Page 168-192)*

Post-Rate Case Filing

Data Responses

The subject matter experts and data response reviewers, review the data requests not only for subject matter accuracy but also with a focus on how understandable the response is to someone outside of that subject matter expert's field. They also review to define complex terminology and acronyms and to confirm that the questions are answered completely.

Technical Sessions

As recommended in the Business Process Audit, the Company finds great value in technical sessions with the Department of Energy and other parties, where our witnesses have the opportunity to help further explain any remaining questions. These sessions allow for the back-and-forth dialogue with the witnesses that is necessary at times to fully explain and address the questions of the staff. As rolling discovery progresses, should the Department find that it would be beneficial to meet and discuss their discovery questions, our team would be open to such a meeting.

In addition, the procedural schedule works in technical sessions to provide the chance for the open dialogue that's helpful for the witnesses to address any open questions from the staff, following the responses to the data requests. Technical Sessions have been a valuable tool throughout many dockets in facilitating discussions that have brought clarity to complex topics that are challenging to provide solely in a written response. We look forward to continued discussions with the Department to ensure that they have the information necessary to evaluate this rate case.

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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-011

Request from: New Hampshire Public Utilities Commission

Witness: Renaud, Paul R., Dickie, Brian J., Coates Jr., Robert S.

Request:

Please demonstrate with analysis and evidence that the frequency and severity of storms has demonstrably increased versus historical storm activity.

Response:

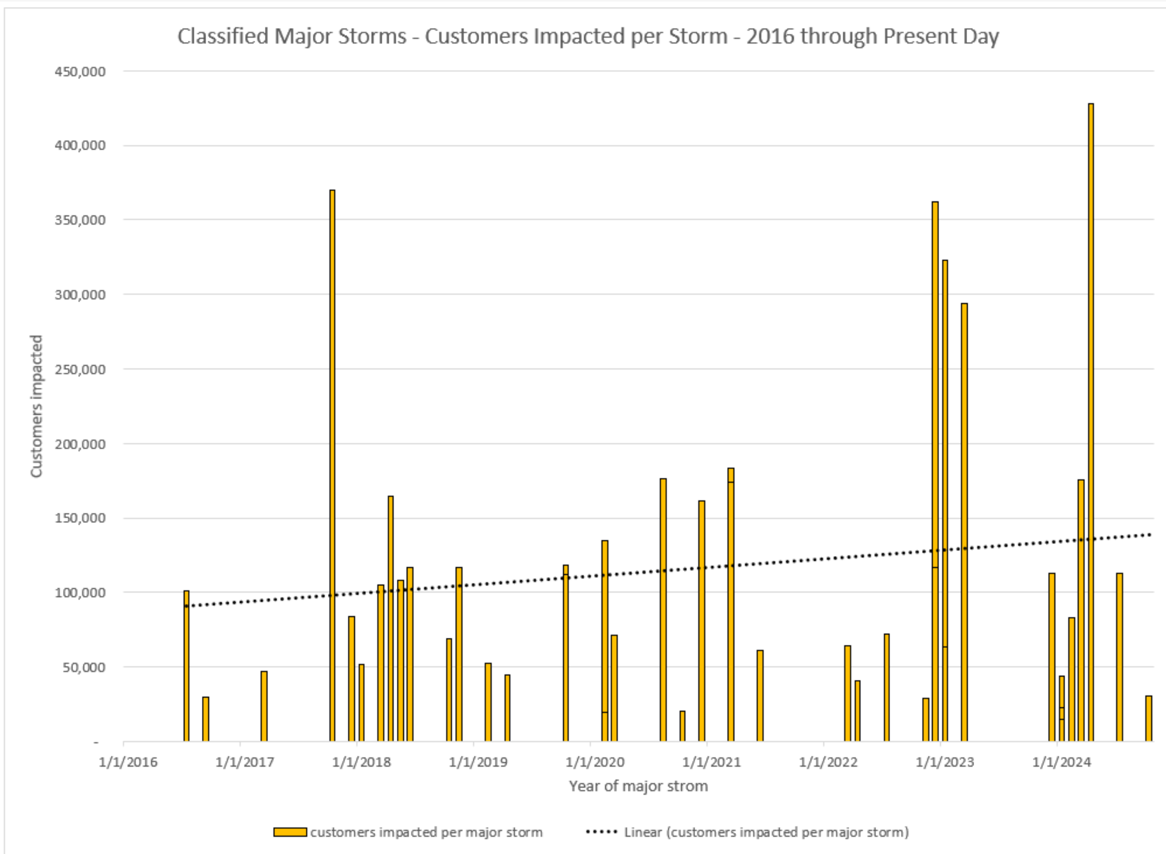
The Company has analyzed the trends in the impact and frequency of storms. Please see Attachment PUC TS1-011 for the trends in the frequency of experienced storm events in PSNH territory. The data in this attachment demonstrates the increasing frequency of storms in the Company's service territory.

Winter storms over the last several years have become more impactful and frequent. The charts below show the classified major storms by customers impacted, events, and overall number of storms per year going back to 2016. In all cases the trend is increasing. Of note are the cluster of winter storms increasing in number per year which tend to be the most impactful in terms of customer impact and difficulty of restoration.

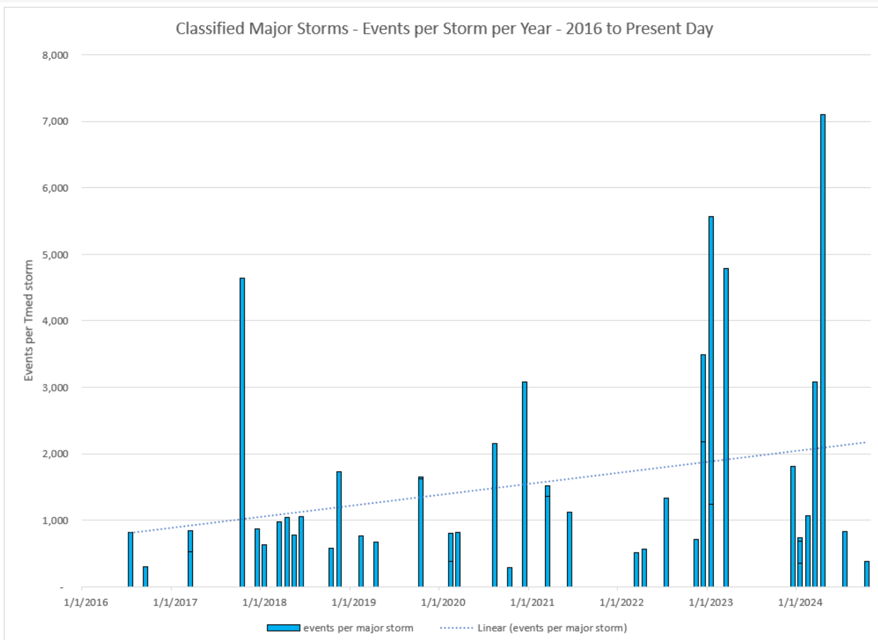
Public Service Company of New Hampshire d/b/a Eversource Energy
Docket No. DE 24-070

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-011

Customers impacted per major storm event:



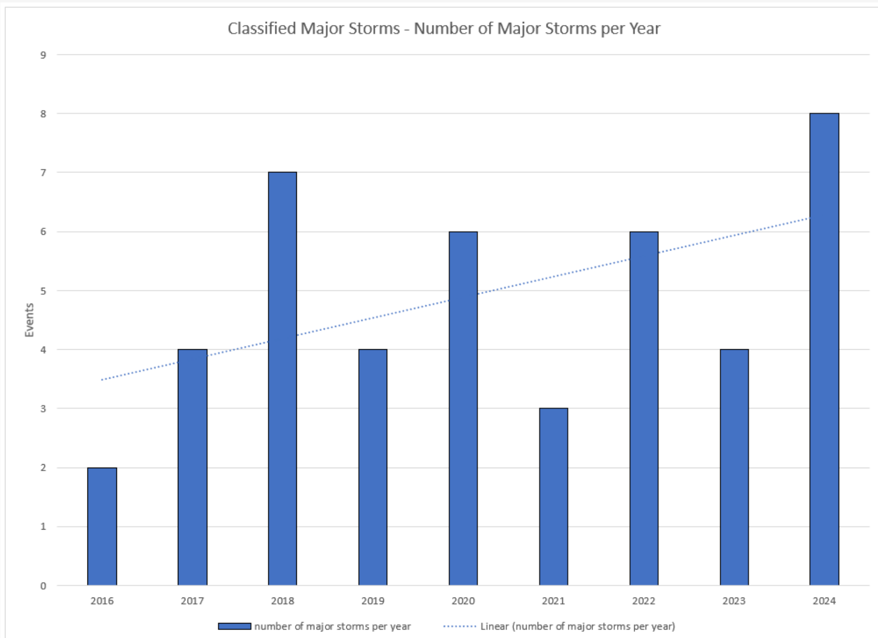
Number of events per storm per year:



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

Date Request Received: October 03, 2024 **Date of Response: November 06, 2024**
Data Request No. PUC TS1-011

Number of major storm events per year:



The New Hampshire Department of Environmental Services ("DES" has also analyzed the trends in weather events impacting New Hampshire (https://www.des.nh.gov/climate-and-sustainability/resiliency-and-adaptation). According to the 2022 New Hampshire Climate Assessment, the state is experiencing more frequent and intense precipitation events.

Request from: New Hampshire Public Utilities Commission

Witness: Renaud, Paul R., Dickie, Brian J., Coates Jr., Robert S.

Request:
Please elaborate as to why the Company deems it necessary to proactively replace infrastructure due to age and asset condition.

Response:

Replacing infrastructure that is at the end of its useful life or is in a condition that may pose a safety risk or no longer perform as intended, is essential for meeting the Company's public service obligations.

Running assets to failure (also referred to as a "break-fix model'") is not the industry best practice, nor is it not aligned with customer expectations of reliability, and results in a more costly operation over time. Declining to proactively replace aging infrastructure that is approaching the end of its useful life by, instead, waiting for it to fail, and fixing it only at that point, introduces increased costs and inefficiencies that contribute to higher (not lower) customer costs, in addition to the negative customer experience and other considerations described below. There are several reasons for this, for instance:

1. Waiting until a device has actually failed before fixing it results in an 'emergent' condition that has to be addressed reactively, rather than proactively. This can result in higher labor and contractor costs by having to pay for overtime or premium time if the damage occurs off-hours or on top of a planned work; increased supply chain costs to the extent there may be added fees for accelerated delivery, or to the extent a substitute device may be used in lieu of the optimal device, had the replacement been proactively designed and planned. Conversely, proactive replacement prior to failure can enable mitigation measures for properly planning, sourcing, and staffing the work.

2. Operating on a "break-fix" model hinders (if not eliminates) the ability to thoughtfully plan and design solutions that could result in overall savings as compared to a piecemeal approach. For instance, if the Company is proactively replacing a device prior to its failure, it is able to consider other necessary upgrades or repairs that would be more efficiently addressed (both from a cost, and a customer experience perspective) at one time, as part of a single project, rather than as multiple different projects (i.e., one on an emergent basis, once the device actually fails and another, or several others, either in the case of additional system failures). Essentially, a "break fix" approach eliminates the ability to co-optimize

investments and projects that can be done at lower overall cost and with fewer service interruptions if proactively planned in advance.

It is for these reasons and those described below that the Company does not operate on a "break-fix" model.

To maintain safe and reliable service, utility companies assess the condition of infrastructure and must replace infrastructure to:

1. Improve reliability.
   - Waiting until an asset fails negatively impacts reliability and may result in avoidable, potentially prolonged, loss of service for customers and safety risks, such as fallen wires or poles. Proactive replacement improves customer experience by avoiding or minimizing service interruptions.

2. Risk management
   - With a proactive replacement approach, resources and material risk can be managed accordingly.

3. Community impact
   - With a proactive replacement approach, the replacement of the asset can occur during times and conditions to minimize impacts on customers and the community. For example, avoid lane or road closure during rush hour traffic or replacing a pole in the dark and having flashing hazard lights shing into people's windows at night. In addition, if service needs to be temporarily disconnected during the replacement of an asset, the Company can time and minimize the outage's impact on customers and businesses.

4. Safety
   - Public safety is the Company's top priority and we do not want assets to become an electric fire or falling object hazard. Further, replacing aging or compromised infrastructure in proactively allows a utility to reduce risk to crews performing the work under controlled, non-emergency conditions.

5. Meet customer demand.
   - When replacing an asset proactively we can notify the customer of the effort taking place, allowing the customer to plan their day based on work in the area. Waiting for failure, does not allow the customer to anticipate the outage, nor does the customer know the duration.

6. Withstand weather events.
    - Infrastructure that is near end of life or degraded may not withstand weather events, which can result in unplanned service interruptions.

    - Further, replacing an asset in a storm condition is not the most cost-effective method, as resources are stretch thin and can be expensive, where possible, it is ideal to manage the risk during normal conditions.

7. Material Planning
    - Replacing poles in a controlled manor allows the utility to control inventory needs and establish an effective turn ratio on its inventory needs with competitive material sourcing.