

STEVEN J. BOYAJIAN

One Financial Plaza, 14th Floor
Providence, RI 02903-2485
Main (401) 709-3300
Fax (401) 709-3399
sboyajian@rc.com
Direct (401) 709-3359

Also admitted in Massachusetts

April 16, 2025

VIA HAND DELIVERY AND ELECTRONIC MAIL

Stephanie De La Rosa, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

**RE: Docket No. 25-04-EL – The Narragansett Electric Company d/b/a Rhode Island Energy
2025 Annual Retail Rate Filing
Response to Public Utilities Commission’s Record Requests (Full Set)**

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the “Company”), I have enclosed the Company’s responses to the Public Utilities Commission’s Record Requests (Full Set) made during the March 20, 2025 hearing in the above-referenced docket.

Thank you for your attention to this matter. If you have any questions, please contact me at (401) 709-3359.

Sincerely,



Steven J. Boyajian

Enclosure

cc: Docket No. 25-04-EL Service List

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Heidi J. Seddon

April 16, 2025

Date

**Rhode Island Energy – 2025 Annual Retail Rate Filing - Docket No. 25-04-EL
Service List Updated 2/26/2025**

Name/Address	E-mail Distribution	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Celia B. O'Brien, Esq. 280 Melrose St. Providence, RI 02907	COBrien@pplweb.com ;	401-578-2700
	JScanlon@pplweb.com ;	
	SBriggs@pplweb.com ;	
	JOliveira@pplweb.com ;	
	ASpinu@ng.rienergy.com ;	
	PBlazunas@ceadvisors.com ;	
Steven J. Boyajian, Esq. Robinson & Cole LLC Robinson & Cole LLP One Financial Plaza 14th Floor Providence, RI 02903	SBoyajian@rc.com ;	401-709-3359
Division of Public Utilities Christy Hetherington, Esq. Division of Public Utilities	Margaret.L.Hogan@dpuc.ri.gov ;	401-222-2424
	John.bell@dpuc.ri.gov ;	
	Joel.munoz@dpuc.ri.gov ;	
	Al.mancini@dpuc.ri.gov ;	
	Donna.Daigle@dpuc.ri.gov ;	
	Al.contente@dpuc.ri.gov ;	
	Christy.hetherington@dpuc.ri.gov ;	
	leo.wold@dpuc.ri.gov ;	
	mark.a.simpkins@dpuc.ri.gov ;	
	gregory.schultz@dpuc.ri.gov ;	
	kyle.j.lynch@dpuc.ri.gov ;	
	Machaela.Seaton@dpuc.ri.gov ;	
	Ellen.golde@dpuc.ri.gov ;	
diana.moniz@dpuc.ri.gov ;		

Daymark Energy Advisors Aliea Munger Louisa Lund	aafnan@daymarkea.com ; llund@daymarkea.com ;	
Original & 9 copies file w/ PUC: Stephanie De La Rosa, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Stephanie.DeLaRosa@puc.ri.gov ;	401-780-2017
	Cynthia.WilsonFrias@puc.ri.gov ;	
	Alan.nault@puc.ri.gov ;	
	Christopher.Caramello@puc.ri.gov ;	
	Todd.bianco@puc.ri.gov ;	
	Kristen.L.Masse@puc.ri.gov ; Jordan.Sasa@puc.ri.gov ;	
Office of Energy Resources Adam Fague, Esq. Christopher Kearns	adam.fague@doa.ri.gov ;	401-222-8880
	nancy.russolino@doa.ri.gov ;	
	Christopher.Kearns@energy.ri.gov ;	
	Shauna.Beland@energy.ri.gov ;	
	William.Owen@energy.ri.gov ;	
Green Development Matt Sullivan	ms@green-ri.com ;	
Conservation Law Foundation Jamie Rhodes, Esq.	jrhodes@clf.org ;	
Good Energy, L.P. Laura Olton, Esq.	laura@isoenergyadvisors.com ;	
	patrick@goodenergy.com ;	
	rafidah.rahman@goodenergy.com ;	

The Narragansett Electric Company
d/b/a Rhode Island Energy
RIPUC Docket No. 25-04-EL
In Re: 2025 Annual Retail Rate Filing
Responses to Record Requests
Issued at the Commission's Evidentiary Hearing
On March 20, 2025

Record Request No. 1

Request:

Expand the analysis in the Company's response to PUC 1-7 using monthly allocators for the entire data table for CY 2024, meaning it might need to include the very end of CY 2023.

Response:

Please refer to Attachment RR-1, which presents the estimated production of Renewable Generation Credit ("RGC") kWh by month for 2024 based on the Company's billing cycles.

I. Billed Renewable Generation Credit kWh (2024) Pro-Ration Percentages

	(A)	(B)	(C)	(D) = (B) + (C)	(E)	(F)
	Month-Year	Billed RGC kWh	Exclude C-06 Customer	Adj. Billed RGC kWh	Pro-Rated to Bill Month (%)	Pro-Rated to Prior Month (%)
(1)	January 2024	(24,840,309)	-	(24,840,309)	43.76%	56.24%
(2)	February 2024	(21,845,117)	-	(21,845,117)	42.21%	57.79%
(3)	March 2024	(48,473,719)	-	(48,473,719)	43.09%	56.91%
(4)	April 2024	(54,306,386)	-	(54,306,386)	41.84%	58.16%
(5)	May 2024	(73,109,480)	-	(73,109,480)	42.20%	57.80%
(6)	June 2024	(80,505,642)	-	(80,505,642)	43.91%	56.09%
(7)	July 2024	(76,204,061)	-	(76,204,061)	45.80%	54.20%
(8)	August 2024	(60,024,207)	-	(60,024,207)	44.38%	55.62%
(9)	September 2024	(62,696,245)	-	(62,696,245)	35.75%	64.25%
(10)	October 2024	(50,686,937)	(644,130)	(50,042,807)	36.97%	63.03%
(11)	November 2024	(96,617,382)	(38,908,658)	(57,708,724)	36.46%	63.54%
(12)	December 2024	(41,976,468)	664,538	(42,641,006)	41.49%	58.51%
(13)	January 2025	(72,508,346)	(38,244,120)	(34,264,226)	43.42%	56.58%

Notes:

- (B) Source: Internal Company Records (RP202 Report)
- (C) Source: Internal Company Records. Please note that the C-06 customer in question had erroneous Renewable Generation Credits included in November 2024 billed revenues that were reversed in December 2024, and again included January 2025 billed revenues that were reversed in February 2025.
- (E) Source: Internal Company Records. For a given month, represents the estimated percentage of that month's billed kWh attributable to that month. For instance, for February 2024, approximately 42.21% of the billed 21,845,117 kWh are estimated to have been produced in February 2024.
- (F) Source: Internal Company Records. For a given month, represents the estimated percentage of that month's billed kWh attributable to the prior month. For instance, for February 2024, approximately 57.79% of the billed 21,845,117 kWh are estimated to have been produced in January 2024.

II. Estimated Billed RGC kWh Production by Month (2024)

	Month-Year	Description	Estimated Production	Calculation:
(14)	January 2024	Produced in January 2024 and Billed in January 2024	(10,870,642)	=(D)(1) x (E)(1)
(15)	January 2024	Produced in January 2024 and Billed in February 2024	(12,624,667)	=(D)(2) x (F)(2)
(16)	February 2024	Produced in February 2024 and Billed in February 2024	(9,220,450)	=(D)(2) x (E)(2)
(17)	February 2024	Produced in February 2024 and Billed in March 2024	(27,587,084)	=(D)(3) x (F)(3)
(18)	March 2024	Produced in March 2024 and Billed in March 2024	(20,886,635)	=(D)(3) x (E)(3)
(19)	March 2024	Produced in March 2024 and Billed in April 2024	(31,583,117)	=(D)(4) x (F)(4)
(20)	April 2024	Produced in April 2024 and Billed in April 2024	(22,723,269)	=(D)(4) x (E)(4)
(21)	April 2024	Produced in April 2024 and Billed in May 2024	(42,255,052)	=(D)(5) x (F)(5)
(22)	May 2024	Produced in May 2024 and Billed in May 2024	(30,854,428)	=(D)(5) x (E)(5)
(23)	May 2024	Produced in May 2024 and Billed in June 2024	(45,155,872)	=(D)(6) x (F)(6)
(24)	June 2024	Produced in June 2024 and Billed in June 2024	(35,349,770)	=(D)(6) x (E)(6)
(25)	June 2024	Produced in June 2024 and Billed in July 2024	(41,305,559)	=(D)(7) x (F)(7)
(26)	July 2024	Produced in July 2024 and Billed in July 2024	(34,898,502)	=(D)(7) x (E)(7)
(27)	July 2024	Produced in July 2024 and Billed in August 2024	(33,383,178)	=(D)(8) x (F)(8)
(28)	August 2024	Produced in August 2024 and Billed in August 2024	(26,641,029)	=(D)(8) x (E)(8)
(29)	August 2024	Produced in August 2024 and Billed in September 2024	(40,280,783)	=(D)(9) x (F)(9)
(30)	September 2024	Produced in September 2024 and Billed in September 2024	(22,415,462)	=(D)(9) x (E)(9)
(31)	September 2024	Produced in September 2024 and Billed in October 2024	(31,539,513)	=(D)(10) x (F)(10)
(32)	October 2024	Produced in October 2024 and Billed in October 2024	(18,503,294)	=(D)(10) x (E)(10)
(33)	October 2024	Produced in October 2024 and Billed in November 2024	(36,668,144)	=(D)(11) x (F)(11)
(34)	November 2024	Produced in November 2024 and Billed in November 2024	(21,040,580)	=(D)(11) x (E)(11)
(35)	November 2024	Produced in November 2024 and Billed in December 2024	(24,950,447)	=(D)(12) x (F)(12)
(36)	December 2024	Produced in December 2024 and Billed in December 2024	(17,690,559)	=(D)(12) x (E)(12)
(37)	December 2024	Produced in December 2024 and Billed in January 2025	(19,386,699)	=(D)(13) x (F)(13)

III. Estimated Billed RGC kWh Production by Month (2024) - Summary

	Month Year	Estimated Production	Monthly Change
(38)	January 2024	(23,495,309)	
(39)	February 2024	(36,807,534)	(13,312,224)
(40)	March 2024	(52,469,752)	(15,662,218)
(41)	April 2024	(64,978,322)	(12,508,570)
(42)	May 2024	(76,010,300)	(11,031,978)
(43)	June 2024	(76,655,328)	(645,029)
(44)	July 2024	(68,281,680)	8,373,648
(45)	August 2024	(66,921,812)	1,359,868
(46)	September 2024	(53,954,974)	12,966,838
(47)	October 2024	(55,171,438)	(1,216,464)
(48)	November 2024	(45,991,027)	9,180,412
(49)	December 2024	(37,077,258)	8,913,769
(50)	Total	(657,814,735)	

Record Request No. 2

Request:

With respect to the mobile transformer referenced in the pre-filed direct testimony of Company witness Alexei Spinu, please indicate: when the purchase of the transformer was initiated and completed; when it was placed in service; when it was actually used; which Company ordered it; the number of 345 kV transmission lines owned by the Company; whether the transformer has been deployed for Rhode Island use or New England use; and whether it was shared with the Company's former Massachusetts affiliates.

Response:

The purchase of a 345/115kV (550MVA) mobile transformer was initiated by the Company in February 2020 and the transformer received in February 2025. This mobile unit was placed into service in February 2025. Rhode Island Energy currently owns nine 345kV circuits, and the purchased equipment addresses the need for mobile coverage for this voltage class in the event of a scheduled or unscheduled transformer change. This equipment can be mobilized and installed approximately twice as quickly as a normal spare. This transformer is wholly owned by Rhode Island Energy and part of Rhode Island Energy's spare equipment strategy to recover all loads and ensure system stability from loss of a transformer.

Record Request No. 3

Request:

Of the \$22 million increase in LNS rates, how much is attributable to the rate issues explained by Mr. Spinu at the Commission's March 20, 2025, hearing and how much is related to other items? What was the contribution to the regional revenue requirement from capital additions to Rhode Island Energy owned transmission facilities? Please break down the contribution by project. Please indicate the total value of capital additions for asset condition projects and for new facilities for 2022, 2023, 2024 and for the period of any forecast that the Company has prepared.

Response:

The LNS rate items discussed by Company witness Alexei Spinu at the Commission's March 20, 2025 hearing, which are also referenced in Mr. Spinu's pre-filed direct testimony beginning at Bates page 430, explain \$19.71 million of the \$22.29 million increase in the Non-PTF demand charge. This total can be derived by adding line 40 and line 43 of Attachment RR 3-1. The explanations provided in Mr. Spinu's pre-filed and hearing testimony are applicable to the retail rate periods of: 1) April to December 2025 which has \$15.14 million of this impact as shown on line 40 of Attachment RR-3-1; and 2) January to March 2026 which has an impact of \$4.57 million, as shown on line 43.

At the time of the Company's Retail Rate filing, the period of January to March 2026 does not have a FERC filed rate, and for this reason the Company incorporates the best available forecast regarding Non-PTF transmission projects planned to be in-service for the 2026 calendar year, as shown in page 3 of schedule AS-6. These transmission projects are layered on top of the currently approved 2025 LNS revenue requirement, to provide the projected increase in the 2026 LNS rate, with the high-level assumption that all other components of the calculation are held constant. The increase in the plant forecast being used for the January to March periods in the 2025 Annual Retail Rate filing compared to similar periods in the 2024 Annual Retail Rate filing, drives an additional \$1.64 million of an increase, as shown in Attachment RR-3-1, line 39 column O.

Lastly, to calculate the Non-PTF demand charge, the Company uses the most recently available load data available at the time of the filing. The increase in the January to December 2024 load compared to January to December 2023 load, drives the remaining \$0.9 million increase as shown in Attachment RR-3-1 line 42.

Rhode Island Energy's estimated local revenue requirement as filed in the FERC approved 2025 LNS rate is \$49,967,128. Of this total, \$7.65 million is related to the incremental revenue

Record Request No. 3, Page 2

requirement due to Non-PTF capital additions forecasted for the 2024 and 2025 in-service periods. The incremental revenue requirement for these projects is calculated by multiplying the projects' projected plant balance times the transmission carrying charge factor, as well as adding an adjustment related to prorated ADIT. As such, attachment RR-3-2 allocated the projected incremental revenue requirement on a per project basis. Similar information regarding regional revenue requirement is provided within the written response in Record Request 4.

Please see the Company's response to Record Request 5 for the identification of asset conditioning projects in Rhode Island Energy's transmission plant.

RIE Non-PTF Demand Charge Forecast
Year-over-Year Driver Explanation

Line	(A) Year	(B) Period	(C) Non-PTF kW Load	(D) Monthly LNS Rate	(E) Non-PTF Charge
2025 Transmission Forecast: Non-PTF Demand Charge Calculation					
1	2025	Apr	1,000,482	\$ 3.55	3,548,733
2	2025	May	1,073,849	\$ 3.55	3,808,967
3	2025	Jun	1,511,551	\$ 3.55	5,361,503
4	2025	Jul	1,612,635	\$ 3.55	5,720,053
5	2025	Aug	1,628,323	\$ 3.55	5,775,698
6	2025	Sep	1,149,730	\$ 3.55	4,078,118
7	2025	Oct	951,572	\$ 3.55	3,375,247
8	2025	Nov	849,446	\$ 3.55	3,013,004
9	2025	Dec	1,148,044	\$ 3.55	4,072,138
10	2025	Jan	1,305,881	\$ 4.14	5,407,300
11	2025	Feb	1,082,582	\$ 4.14	4,482,680
12	2025	Mar	908,987	\$ 4.14	3,763,870
13	12-Mo Total		1,210,372	\$ 3.70	52,407,311

2024 Transmission Forecast: Non-PTF Demand Charge Calculation					
14	2024	Apr	882,771	\$ 2.16	1,908,153
15	2024	May	900,475	\$ 2.16	1,946,420
16	2024	Jun	1,074,455	\$ 2.16	2,322,488
17	2024	Jul	1,503,623	\$ 2.16	3,250,155
18	2024	Aug	1,273,810	\$ 2.16	2,753,403
19	2024	Sep	1,461,167	\$ 2.16	3,158,384
20	2024	Oct	986,961	\$ 2.16	2,133,365
21	2024	Nov	848,689	\$ 2.16	1,834,483
22	2024	Dec	1,145,202	\$ 2.16	2,475,409
23	2024	Jan	1,199,182	\$ 2.26	2,705,819
24	2024	Feb	1,486,963	\$ 2.26	3,355,166
25	2024	Mar	1,007,031	\$ 2.26	2,272,252
26	12-Mo Total		1,160,300	\$ 2.19	30,115,497

2025 Transmission Forecast: Non-PTF Demand Charge Calculation					
2025	Apr	1,000,482	\$ 3.55	3,548,733	
2025	May	1,073,849	\$ 3.55	3,808,967	
2025	Jun	1,511,551	\$ 3.55	5,361,503	
2025	Jul	1,612,635	\$ 3.55	5,720,053	
2025	Aug	1,628,323	\$ 3.55	5,775,698	
2025	Sep	1,149,730	\$ 3.55	4,078,118	
2025	Oct	951,572	\$ 3.55	3,375,247	
2025	Nov	849,446	\$ 3.55	3,013,004	
2025	Dec	1,148,044	\$ 3.55	4,072,138	
2025	Jan	1,305,881	\$ 3.55	4,631,988	
2025	Feb	1,082,582	\$ 3.55	3,839,942	
2025	Mar	908,987	\$ 3.55	3,224,197	
12-Mo Total		1,210,372	\$ 3.55	50,449,588	

2024 Transmission Forecast: Non-PTF Demand Charge Calculation					
2024	Apr	882,771	\$ 2.16	1,908,153	
2024	May	900,475	\$ 2.16	1,946,420	
2024	Jun	1,074,455	\$ 2.16	2,322,488	
2024	Jul	1,503,623	\$ 2.16	3,250,155	
2024	Aug	1,273,810	\$ 2.16	2,753,403	
2024	Sep	1,461,167	\$ 2.16	3,158,384	
2024	Oct	986,961	\$ 2.16	2,133,365	
2024	Nov	848,689	\$ 2.16	1,834,483	
2024	Dec	1,145,202	\$ 2.16	2,475,409	
2024	Jan	1,199,182	\$ 2.16	2,592,090	
2024	Feb	1,486,963	\$ 2.16	3,214,144	
2024	Mar	1,007,031	\$ 2.16	2,176,747	
12-Mo Total		1,160,300	\$ 2.16	29,765,240	

Variance

Line	Year	Period	Non-PTF kW Load Variance	Monthly LNS Rate Variance	Non-PTF Charge Variance
27	YoY	Apr	117,711	\$ 1.39	1,640,580
28	YoY	May	173,375	\$ 1.39	1,862,547
29	YoY	Jun	437,095	\$ 1.39	3,039,016
30	YoY	Jul	109,012	\$ 1.39	2,469,899
31	YoY	Aug	354,513	\$ 1.39	3,022,294
32	YoY	Sep	(311,437)	\$ 1.39	919,734
33	YoY	Oct	(35,389)	\$ 1.39	1,241,882
34	YoY	Nov	757	\$ 1.39	1,178,521
35	YoY	Dec	2,842	\$ 1.39	1,596,728
36	YoY	Jan	106,699	\$ 1.88	2,701,481
37	YoY	Feb	(404,381)	\$ 1.88	1,127,514
38	YoY	Mar	(98,044)	\$ 1.88	1,491,617
39	12-Mo Total		37,729	\$ 1.51	22,291,814

Month to Month Breakout by Driver

Non-PTF kW Load Driver	Monthly LNS Rate Driver	Sum of Non- PTF Drivers
254,438	1,386,142	1,640,580
374,758	1,487,790	1,862,547
944,803	2,094,213	3,039,016
235,635	2,234,263	2,469,899
766,296	2,255,998	3,022,294
(673,186)	1,592,920	919,734
(76,496)	1,318,378	1,241,882
1,636	1,176,885	1,178,521
6,144	1,590,584	1,596,728
240,754	2,460,727	2,701,481
(912,441)	2,039,956	1,127,514
(221,226)	1,712,843	1,491,617
941,116	21,350,698	22,291,814

Variance

Year	Period	Non-PTF kW Load Variance	Monthly LNS Rate Variance	Non-PTF Charge Variance	Monthly LNS Rate Driver	Sum of Non- PTF Drivers
YoY	Apr	117,711	\$ 1.39	1,640,580	1,386,142	-
YoY	May	173,375	\$ 1.39	1,862,547	1,487,790	-
YoY	Jun	437,095	\$ 1.39	3,039,016	2,094,213	-
YoY	Jul	109,012	\$ 1.39	2,469,899	2,234,263	-
YoY	Aug	354,513	\$ 1.39	3,022,294	2,255,998	-
YoY	Sep	(311,437)	\$ 1.39	919,734	1,592,920	-
YoY	Oct	(35,389)	\$ 1.39	1,241,882	1,318,378	-
YoY	Nov	757	\$ 1.39	1,178,521	1,176,885	-
YoY	Dec	2,842	\$ 1.39	1,596,728	1,590,584	-
YoY	Jan	106,699	\$ 1.39	2,039,898	1,809,263	651,464
YoY	Feb	(404,381)	\$ 1.39	625,798	1,499,889	540,067
YoY	Mar	(98,044)	\$ 1.39	1,047,450	1,259,377	453,466
12-Mo Total		37,729	\$ 1.39	20,684,348	#####	1,644,996

Variance related to FERC filed LNS rates for periods of Jan - Dec 2025

40 15,137,173

Variance related to Company's forecasted LNS rate (not filed with FERC) for periods of Jan - Mar 2026, which includes \$1.64m increase related to just the addition of 2026 capital additions

41 6,213,525

Variance due to load

42 941,116

Variance related to if keeping FERC filed LNS rates for periods of Jan - Dec 2025 constant through Jan - Mar 2026

43 4,568,529

Narragansett Electric Company d/b/a Rhode Island Energy
Annual Transmission Revenue Requirements (ATTR)
Per Attachment 2 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff
Forecasted Local Network Service ("LNS") Plant Additions
Attachment Supplemental - RIE - 2
CY2024 & CY2025 Forecasted Plant Additions

Line No.	(A) Project Title	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
		2024 Total In-Service Forecast	Carrying Charge Factor	Incremental Revenue Requirement	Forecasted ADIT Adjustment	Estimated Revenue Requirement Impact	2025 5-Q AVERAGE In-Service Forecast	Carrying Charge Factor	Incremental Revenue Requirement	Forecasted ADIT Adjustment	Estimated Revenue Requirement Impact
1	01 M13L14X RBLD 115 LINE	\$ 494,717	14.16%	\$ 70,031	\$ (3,544)	\$ 66,486	\$ 6,694,050	14.16%	\$ 947,591	\$ (29,787)	\$ 917,803
2	02 M13L14 RBLD 115 LINE	\$ -	14.16%	\$ -	\$ -	\$ -	\$ 10,844,105	14.16%	\$ 1,535,061	\$ (48,254)	\$ 1,486,806
3	TIVER TAP RBLD 115KV Line	\$ -	14.16%	\$ -	\$ -	\$ -	\$ 1,505,041	14.16%	\$ 213,049	\$ (6,697)	\$ 206,352
4	Woonsocket to Nasonville T L	\$ -	14.16%	\$ -	\$ -	\$ -	\$ 1,536,401	14.16%	\$ 217,489	\$ (6,837)	\$ 210,652
5	VHV Narragansett ElecTransformer	\$ 18,589,033	14.16%	\$ 2,631,411	\$ (133,180)	\$ 2,498,231	\$ -	14.16%	\$ -	\$ -	\$ -
6	WNOB INST PMU	\$ 181,831	14.16%	\$ 25,739	\$ (1,303)	\$ 24,437	\$ -	14.16%	\$ -	\$ -	\$ -
7	FRASQ INST PMU	\$ 121,507	14.16%	\$ 17,200	\$ (871)	\$ 16,330	\$ -	14.16%	\$ -	\$ -	\$ -
8	S171N-4 PUTPI TAP WPR 115 POLE	\$ 166,466	14.16%	\$ 23,564	\$ (1,193)	\$ 22,372	\$ -	14.16%	\$ -	\$ -	\$ -
9	I187/J188 Insulator Replacement	\$ 96,336	14.16%	\$ 13,637	\$ (690)	\$ 12,947	\$ -	14.16%	\$ -	\$ -	\$ -
10	3311/3312 Pole Replacement	\$ 964,791	14.16%	\$ 136,573	\$ (6,912)	\$ 129,661	\$ -	14.16%	\$ -	\$ -	\$ -
11	I187/J188 4 structure replacements	\$ 568,967	14.16%	\$ 80,541	\$ (4,076)	\$ 76,465	\$ -	14.16%	\$ -	\$ -	\$ -
12	S03- 3763 Jepson-Gate II C-Tag Repl	\$ 540,000	14.16%	\$ 76,441	\$ (3,869)	\$ 72,572	\$ -	14.16%	\$ -	\$ -	\$ -
13	S04- B23 NASON-WFARN C-Tag Repl	\$ 135,000	14.16%	\$ 19,110	\$ (967)	\$ 18,143	\$ -	14.16%	\$ -	\$ -	\$ -
14	01 WOON-NASO PUR 115KV ROW	\$ 501,015	14.16%	\$ 70,922	\$ (3,589)	\$ 67,333	\$ -	14.16%	\$ -	\$ -	\$ -
15	01 BLOIS UPGR DILCO 34.5kv RELAY	\$ 159,664	14.16%	\$ 22,602	\$ (1,144)	\$ 21,458	\$ -	14.16%	\$ -	\$ -	\$ -
16	04 KENCO INSTALL 345/115KV XFMR	\$ 81,561	14.16%	\$ 11,546	\$ (584)	\$ 10,961	\$ -	14.16%	\$ -	\$ -	\$ -
17	S171-2/3 Steel Structure Inspection	\$ 119,000	14.16%	\$ 16,845	\$ (853)	\$ 15,993	\$ -	14.16%	\$ -	\$ -	\$ -
18	01 RIVE 115KV CB Mon INSTL	\$ 291,536	14.16%	\$ 41,269	\$ (2,089)	\$ 39,180	\$ -	14.16%	\$ -	\$ -	\$ -
19	Avian Gaurding - Phase 2	\$ 1,389,231	14.16%	\$ 196,656	\$ (9,953)	\$ 186,703	\$ -	14.16%	\$ -	\$ -	\$ -
20	New Lafayette Substation 115-12 kV	\$ -	14.16%	\$ -	\$ -	\$ -	\$ 5,111,109	14.16%	\$ 723,514	\$ (22,744)	\$ 700,771
21	Q143S Taps to New Admiral St	\$ -	14.16%	\$ -	\$ -	\$ -	\$ 817,961	14.16%	\$ 115,788	\$ (3,640)	\$ 112,148
22	ProvStudy Admiral St Ckt SW T-Sub	\$ -	14.16%	\$ -	\$ -	\$ -	\$ 1,827,890	14.16%	\$ 258,751	\$ (8,134)	\$ 250,617
23	01 CHASE PUR LAND	\$ 680,000	14.16%	\$ 96,259	\$ (4,872)	\$ 91,387	\$ -	14.16%	\$ -	\$ -	\$ -
24	02 WOORI PUR LAND	\$ 350,000	14.16%	\$ 49,545	\$ (2,508)	\$ 47,037	\$ -	14.16%	\$ -	\$ -	\$ -
25	03 KENYO PUR LAND	\$ 350,000	14.16%	\$ 49,545	\$ (2,508)	\$ 47,037	\$ -	14.16%	\$ -	\$ -	\$ -
26	04 HARTAV PUR LAND	\$ 350,000	14.16%	\$ 49,545	\$ (2,508)	\$ 47,037	\$ -	14.16%	\$ -	\$ -	\$ -
27	05 WKING PUR LAND	\$ 350,000	14.16%	\$ 49,545	\$ (2,508)	\$ 47,037	\$ -	14.16%	\$ -	\$ -	\$ -
28	WFARN 345-115 XFMR	\$ -	14.16%	\$ -	\$ -	\$ -	\$ 1,505,952	14.16%	\$ 213,178	\$ (6,701)	\$ 206,477
29		26,480,655		3,748,527	(189,719)	3,558,807	29,842,510		4,224,421	(132,794)	4,091,627

Record Request No. 4

Request:

With respect to ISO RNS charges, for transmission assets owed by Rhode Island Energy that flow through RNS rates please answer the same questions as those set forth in Record Request 3 with respect to LNS rates. Please explain in the response Rhode Island's contribution to the RNS charges as they flow back to Rhode Island. Please break down the revenue requirement by Rhode Island Energy's contribution and explain the drivers of that contribution. Referencing the table on Bates page 434, line 6, column (b), relate the \$130 million to the actual increase in RNS charges.

Response:

Of the \$39.98 million increase in the PTF demand charge, \$36.64 million is related to the year-over-year increase in the FERC filed RNS rate and can be derived by adding line 40 and line 43 of Attachment RR 4-1. The FERC filed RNS rate covers the retail periods of: 1) April to December 2025, where the increase is related to \$28.15 million as shown on line 40; and 2) January to March 2026 where the increase is related to \$8.49 million, as shown on line 43. At the time of the Company's Retail Rate filing, the period of January to March 2026 does not have a FERC filed rate, and for this reason the Company incorporates the best available forecast of PTF projects planned to be in-service for the 2026 calendar year, as reported in the regional system planning and asset conditioning lists from ISO-NE.

These transmission projects are layered on top of the currently approved 2025 RNS revenue requirement to provide the projected increase in the 2026 RNS rate, with the high-level assumption that all other components of the calculation are held constant. The increase in the plant forecast being used for the January to March periods in the 2025 annual Retail Rate filing compared to similar periods in the 2024 annual Retail Rate filing drives an additional \$10,000 of the increase, as shown on Attachment RR-4-1, line 39 column O. Lastly, to calculate the PTF demand charge, the Company uses the most recent available load data at the time of the filing. The increase in the January to December 2024 load compared to January to December 2023 load, drives the remaining \$3.3 million increase as shown in Attachment RR-4-1 line 42.

Rhode Island Energy's estimated regional revenue requirement as filed in the FERC approved 2025 RNS rate is \$131,885,264. Of this total, \$9.7 million is related to the incremental revenue requirement due to PTF capital additions forecasted for the 2024 and 2025 in-service periods. The incremental revenue requirement for these projects is calculated by multiplying the projects' projected plant balance by the transmission carrying charge factor, as well as adding an

Record Request No. 4, Page 2

adjustment related to prorated ADIT. As such, Attachment RR-4-2 allocated the projected incremental revenue requirement on a per project basis.

The \$30.92 increase in RNS rate from \$154.35/kW to \$185.28/kW was provided by the Rates Working Group, and is referenced in the pre-filed direct testimony of Company witness Alexei Spinu on Bates page 433. This page of Mr. Spinu's testimony also shows the breakdown of this increase by each New England Transmission Owner ("NETO"), and shows that Rhode Island Energy is responsible for \$0.29/kW of this increase, related to the increase in year-over-year forecast. The \$0.29/kW increase in RNS rates is driven by Rhode Island Energy's increase in RNS revenue requirement from \$130.3 million to \$131.9 million. The \$1.6 million year-over-year increase in regional revenue requirement is mostly attributable to incremental additions of forecasted PTF projects.

The calculation of the RNS rate is the total NETO regional revenue requirement, divided by the average load used to service all customers under each NETO. As such, the total cost of the regional revenue requirement is allocated to all of New England customers that take RNS service from the ISO on a \$/kW basis. Under this calculation, the Company can, to the best of its knowledge, allocate how its own revenue requirement is allocated to all New England customers, including those in Rhode Island specifically. Attachment RR 4-3 provides an illustration of how the \$185.28 RNS rate could be allocated to Rhode Island Energy, when allocating from a revenue requirement perspective. Of the \$3.3 billion regional revenue requirement, Rhode Island Energy's revenue requirement is \$131.9 million, or 4 percent of the total. Using this methodology, of the total PTF demand charge of \$220.95 million that is assessed to Rhode Island retail customers, roughly 4 percent or \$8.8 million is related to Rhode Island Energy costs.

Please see the Company's response to Record Request 5 for the identification of asset conditioning projects in Rhode Island Energy's transmission plant.

ISO-NE PTF Demand Charge Forecast
Year-over-Year Driver Explanation

Line	(A) Year	(B) Period	(C) PTF kW Load	(D) RNS Rate	(E) PTF Charge	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
2025 Transmission Forecast: PTF Demand Charge Calculation															
1	2025	Apr	1,000,489	\$ 185.28	15,447,311										
2	2025	May	1,073,854	\$ 185.28	16,580,049										
3	2025	Jun	1,511,554	\$ 185.28	23,338,032										
4	2025	Jul	1,612,638	\$ 185.28	24,898,745										
5	2025	Aug	1,628,326	\$ 185.28	25,140,964										
6	2025	Sep	1,149,735	\$ 185.28	17,751,633										
7	2025	Oct	951,576	\$ 185.28	14,692,106										
8	2025	Nov	849,450	\$ 185.28	13,115,305										
9	2025	Dec	1,148,052	\$ 185.28	17,725,648										
10	2025	Jan	1,305,888	\$ 190.41	20,721,178										
11	2025	Feb	1,078,942	\$ 190.41	17,120,112										
12	2025	Mar	908,994	\$ 190.41	14,423,462										
13	12-Mo Total		1,210,046	\$ 188.56	220,954,546										

2025 Transmission Forecast: PTF Demand Charge Calculation															
2025	Apr		1,000,489	\$ 185.28	15,447,311										
2025	May		1,073,854	\$ 185.28	16,580,049										
2025	Jun		1,511,554	\$ 185.28	23,338,032										
2025	Jul		1,612,638	\$ 185.28	24,898,745										
2025	Aug		1,628,326	\$ 185.28	25,140,964										
2025	Sep		1,149,735	\$ 185.28	17,751,633										
2025	Oct		951,576	\$ 185.28	14,692,106										
2025	Nov		849,450	\$ 185.28	13,115,305										
2025	Dec		1,148,052	\$ 185.28	17,725,648										
2025	Jan		1,305,888	\$ 185.28	20,162,598										
2025	Feb		1,078,942	\$ 185.28	16,658,606										
2025	Mar		908,994	\$ 185.28	14,034,650										
12-Mo Total			1,210,046	\$ 185.28	219,545,648										

2024 Transmission Forecast: PTF Demand Charge Calculation															
14	2024	Apr	895,741	\$ 154.35	11,521,760										
15	2024	May	910,582	\$ 154.35	11,712,657										
16	2024	Jun	1,090,507	\$ 154.35	14,027,001										
17	2024	Jul	1,523,161	\$ 154.35	19,592,154										
18	2024	Aug	1,291,682	\$ 154.35	16,614,680										
19	2024	Sep	1,481,507	\$ 154.35	19,056,366										
20	2024	Oct	1,000,018	\$ 154.35	12,863,057										
21	2024	Nov	862,388	\$ 154.35	11,092,746										
22	2024	Dec	1,159,142	\$ 154.35	14,909,841										
23	2024	Jan	1,212,271	\$ 159.45	16,108,051										
24	2024	Feb	1,499,267	\$ 159.45	19,921,510										
25	2024	Mar	1,019,815	\$ 159.45	13,550,792										
26	12-Mo Total		1,175,115	\$ 155.63	180,970,614										

2024 Transmission Forecast: PTF Demand Charge Calculation															
2024	Apr		895,741	\$ 154.35	11,521,760										
2024	May		910,582	\$ 154.35	11,712,657										
2024	Jun		1,090,507	\$ 154.35	14,027,001										
2024	Jul		1,523,161	\$ 154.35	19,592,154										
2024	Aug		1,291,682	\$ 154.35	16,614,680										
2024	Sep		1,481,507	\$ 154.35	19,056,366										
2024	Oct		1,000,018	\$ 154.35	12,863,057										
2024	Nov		862,388	\$ 154.35	11,092,746										
2024	Dec		1,159,142	\$ 154.35	14,909,841										
2024	Jan		1,212,271	\$ 154.35	15,593,230										
2024	Feb		1,499,267	\$ 154.35	19,284,809										
2024	Mar		1,019,815	\$ 154.35	13,117,702										
12-Mo Total			1,175,115	\$ 154.35	179,386,002										

Variance

Month to Month Drivers

Variance

Line	Year	Period	PTF kW Load Variance	Monthly RNS Rate Variance	PTF Charge Variance	PTF kW Load Driver	Monthly RNS		Sum of PTF Drivers	Year	Period	PTF kW Load Variance	Monthly RNS Rate Variance	PTF Charge Variance	Monthly RNS Rate Driver	Variance due to 2026 PTF Forecast
							Rate Driver	Sum of PTF Drivers								
27	YoY	Apr	104,748	\$ 30.92	3,925,551	1,347,355	2,578,196	3,925,551	YoY	Apr	104,748	\$ 30.92	3,925,551	2,578,196	-	
28	YoY	May	163,272	\$ 30.92	4,867,392	2,100,139	2,767,253	4,867,392	YoY	May	163,272	\$ 30.92	4,867,392	2,767,253	-	
29	YoY	Jun	421,047	\$ 30.92	9,311,031	5,415,854	3,895,177	9,311,031	YoY	Jun	421,047	\$ 30.92	9,311,031	3,895,177	-	
30	YoY	Jul	89,477	\$ 30.92	5,306,591	1,150,927	4,155,664	5,306,591	YoY	Jul	89,477	\$ 30.92	5,306,591	4,155,664	-	
31	YoY	Aug	336,644	\$ 30.92	8,526,284	4,330,193	4,196,091	8,526,284	YoY	Aug	336,644	\$ 30.92	8,526,284	4,196,091	-	
32	YoY	Sep	(331,772)	\$ 30.92	(1,304,732)	(4,267,525)	2,962,793	(1,304,732)	YoY	Sep	(331,772)	\$ 30.92	(1,304,732)	2,962,793	-	
33	YoY	Oct	(48,442)	\$ 30.92	1,829,049	(623,101)	2,452,150	1,829,049	YoY	Oct	(48,442)	\$ 30.92	1,829,049	2,452,150	-	
34	YoY	Nov	(12,938)	\$ 30.92	2,022,559	(166,419)	2,188,978	2,022,559	YoY	Nov	(12,938)	\$ 30.92	2,022,559	2,188,978	-	
35	YoY	Dec	(11,090)	\$ 30.92	2,815,807	(142,649)	2,958,456	2,815,807	YoY	Dec	(11,090)	\$ 30.92	2,815,807	2,958,456	-	
36	YoY	Jan	93,617	\$ 30.96	4,613,127	1,243,936	3,369,191	4,613,127	YoY	Jan	93,617	\$ 30.92	4,569,368	3,365,189	4,002	
37	YoY	Feb	(420,325)	\$ 30.96	(2,801,398)	(5,585,068)	2,783,670	(2,801,398)	YoY	Feb	(420,325)	\$ 30.92	(2,628,203)	2,780,364	3,306	
38	YoY	Mar	(110,821)	\$ 30.96	872,670	(1,472,534)	2,345,205	872,670	YoY	Mar	(110,821)	\$ 30.92	916,948	2,342,419	2,785	
39	12-Mo Total		22,785	\$ 30.93	39,983,932	3,331,108	36,652,825	39,983,932	12-Mo Total		22,785	\$ 30.92	40,159,646	36,642,731	10,093	

Variance related to FERC filed RNS rates for the periods of Jan - Dec 2025

40 28,154,759

Variance related to NETO's RSP & ACL forecasted plant additions layered into RNS rate (not filed with FERC) for periods of Jan - Mar 2026, which includes \$10k increase related to just the 2026 capital additions

41 8,498,066

Variance due to load

42 3,331,108

Variance related to if keeping FERC filed RNS rates for periods of Jan - Dec 2025 constant through Jan - Mar 2026

43 8,487,972

Narragansett Electric Company d/b/a Rhode Island Energy

Annual Transmission Revenue Requirements (ATRR)

Per Attachment 1 of Appendix B to Attachment F of the ISO New England Inc. Open Access Transmission Tariff

Forecasted Regional Network Service ("RNS") Plant Additions

Attachment Supplemental - RIE - 2

CY2024 & CY2025 Forecasted Plant Additions

Line No.	(A) Project Title	(B) 2024 Total In-Service Forecast	(C) Carrying Charge Factor	(D) Incremental Revenue Requirement	(E) Forecasted ADIT Adjustment	(F) Estimated Revenue Requirement Impact	(G) 2025 5-Q AVERAGE In-Service Forecast	(H) Carrying Charge Factor	(I) Incremental Revenue Requirement	(J) Forecasted ADIT Adjustment	(K) Estimated Revenue Requirement Impact
1	V148S Rebuild RI	\$ 930,788	14.72%	\$ 137,053	\$ (15,564)	\$ 121,489	\$ -	14.72%	\$ -	\$ -	\$ -
2	L190 ACR	\$ 8,430,905	14.72%	\$ 1,241,401	\$ (140,973)	\$ 1,100,428	\$ -	14.72%	\$ -	\$ -	\$ -
3	315 Line ACR	\$ 16,680,099	14.72%	\$ 2,456,045	\$ (278,907)	\$ 2,177,138	\$ 17,955,200	14.72%	\$ 2,643,796	\$ (226,182)	\$ 2,417,614
4	315 ACR -Phase 2	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 2,136,503	14.72%	\$ 314,587	\$ (26,914)	\$ 287,674
5	01.2 S171N WOONS-HARAV RPLC 115 POLE	\$ 2,420,877	14.72%	\$ 356,460	\$ (40,479)	\$ 315,980	\$ 3,004,912	14.72%	\$ 442,455	\$ (37,853)	\$ 404,602
6	05 T172N WOONS-HARAV UPGR 115 OPGW	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 6,199,126	14.72%	\$ 912,784	\$ (78,091)	\$ 834,694
7	01 WOONS PUR 115 /CB 3 RPL	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 752,674	14.72%	\$ 110,827	\$ (9,481)	\$ 101,345
8	02 WOONS INST 115 CB MON	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 450,000	14.72%	\$ 66,260	\$ (5,669)	\$ 60,591
9	02 WOONS INST 115 BAT MON	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 75,000	14.72%	\$ 11,043	\$ (945)	\$ 10,099
10	02 WOORI RPL 115 1870 CB/BATT	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 165,000	14.72%	\$ 24,295	\$ (2,079)	\$ 22,217
11	02 VALLEY INST 115 CB MON /BATT	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 192,000	14.72%	\$ 28,271	\$ (2,419)	\$ 25,852
12	01.2 WFARN INSTALL 115 FIBER	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 140,534	14.72%	\$ 20,693	\$ (1,770)	\$ 18,923
13	01.2 WOONS INSTALL 115 FIBER	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 70,566	14.72%	\$ 10,390	\$ (889)	\$ 9,501
14	WFARN -SUB MONITOR	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 181,041	14.72%	\$ 26,657	\$ (2,281)	\$ 24,377
15	HTAV CB /MONIT UPGR	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 211,610	14.72%	\$ 31,158	\$ (2,666)	\$ 28,493
16	02 KENYO RPL 115 85-62 CB	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 51,000	14.72%	\$ 7,509	\$ (642)	\$ 6,867
17	SHFAR 345 MONITORING	\$ 911,593	14.72%	\$ 134,227	\$ (15,243)	\$ 118,984	\$ -	14.72%	\$ -	\$ -	\$ -
18	PAWTU Monitor	\$ 410,000	14.72%	\$ 60,370	\$ (6,856)	\$ 53,514	\$ -	14.72%	\$ -	\$ -	\$ -
19	01 KENCO UPGR SECURITY	\$ 3,200,000	14.72%	\$ 471,181	\$ (53,507)	\$ 417,674	\$ 520,000	14.72%	\$ 76,567	\$ (6,550)	\$ 70,016
20	01 SHFARM UPGR SECURITY	\$ 2,650,000	14.72%	\$ 390,197	\$ (44,311)	\$ 345,886	\$ 504,000	14.72%	\$ 74,211	\$ (6,349)	\$ 67,862
21	01 WFARN UPGR SECURITY	\$ -	14.72%	\$ -	\$ -	\$ -	\$ 2,760,000	14.72%	\$ 406,394	\$ (34,768)	\$ 371,626
22	01 LINE 328 INSTL DLR	\$ 338,347	14.72%	\$ 49,820	\$ (5,657)	\$ 44,162	\$ -	14.72%	\$ -	\$ -	\$ -
23	01 LINE 328 IT INST SW	\$ 68,628	14.72%	\$ 10,105	\$ (1,148)	\$ 8,958	\$ -	14.72%	\$ -	\$ -	\$ -
24	01 LINE 1870 IT INST SW	\$ 274,503	14.72%	\$ 40,419	\$ (4,590)	\$ 35,829	\$ -	14.72%	\$ -	\$ -	\$ -
25	01A LINE 1870S INSTL DLR	\$ 195,089	14.72%	\$ 28,726	\$ (3,262)	\$ 25,464	\$ -	14.72%	\$ -	\$ -	\$ -
26	01B LINE 1870 INSTL DLR	\$ 62,634	14.72%	\$ 9,222	\$ (1,047)	\$ 8,175	\$ -	14.72%	\$ -	\$ -	\$ -
27	01C LINE 1870N INSTL DLR	\$ 158,455	14.72%	\$ 23,332	\$ (2,650)	\$ 20,682	\$ -	14.72%	\$ -	\$ -	\$ -
28	01 LINE H17 INSTL DLR	\$ 264,198	14.72%	\$ 38,902	\$ (4,418)	\$ 34,484	\$ -	14.72%	\$ -	\$ -	\$ -
29	01 LINE H17 IT INST SW	\$ 137,246	14.72%	\$ 20,209	\$ (2,295)	\$ 17,914	\$ -	14.72%	\$ -	\$ -	\$ -
30	NPCC DIR1: G185S OPGW Installaion	\$ 518,102	14.72%	\$ 76,287	\$ (8,663)	\$ 67,624	\$ -	14.72%	\$ -	\$ -	\$ -
31	South Street Substation Rebuild	\$ 93,829	14.72%	\$ 13,816	\$ (1,569)	\$ 12,247	\$ -	14.72%	\$ -	\$ -	\$ -
32	RIE- Block Island Improvments	\$ 323,014	14.72%	\$ 47,562	\$ (5,401)	\$ 42,161	\$ -	14.72%	\$ -	\$ -	\$ -
33		\$ 38,068,307		\$ 5,605,331	\$ (636,539)	\$ 4,968,792	\$ 35,369,166		\$ 5,207,899	\$ (445,546)	\$ 4,762,353

Schedule 9
REGIONAL NETWORK SERVICE (RNS)
ISO New England Inc. Open Access Transmission Tariff (OATT)
PTO Regional Revenue Requirements
Attachment Supplemental - 2
For 2025

Line No.	(B) Customer Name	(E) 2025 Forecasted Regional Revenue Requirements
1	Braintree Electric Light Department	\$ 3,836,553
2	Central Maine Power Company	234,791,065
3	Chicopee Municipal Lighting Plant	793,173
4	Connecticut Transmission Municipal	11,224,068
5	The Connecticut Light and Power Company	847,033,535
6	NSTAR Electric Company (West)	227,653,048
7	Public Service Company of New Hampshire	426,472,753
8	Fitchburg Gas and Electric Light	726,896
9	Holyoke Gas & Electric Department	5,023,866
10	Hudson Light & Power Department	-
11	Central Maine Power Company	21,350,494
12	Massachusetts Municipal Wholesale Electric Company	5,208,550
13	Middleborough Gas & Electric Department	1,541,807
14	New England Power Company	485,431,070
15	New Hampshire Transmission, LLC	28,423,993
16	Norwood Municipal Light Department	5,568,376
17	NSTAR Electric Company	450,379,296
18	Reading Municipal Light Department	16,406
19	Rhode Island Energy	131,885,264
20	Shrewsbury Electric & Cable Operations	55,767
21	Taunton Municipal Lighting Plant	1,357,207
22	Unitil Power Corporation	56,004
23	United Illuminating Company, T	175,889,716
24	Vermont Transco LLC	207,930,507
25	Emera Maine	44,824,904
26	Town of Wallingford CT Dept of	1,404,178
27	Total (Sum Line 1 thru Line 26)	\$ 3,318,878,495
28	Average 12 Month Coincident Regional Network Loads	\$ 17,913,050
29	RNS Rate per kilowatt-year (Line 27 / Line 28)	\$185.2771

Record Request No. 5

Request:

Please provide the total dollars of capital additions of Rhode Island Energy owned transmission facilities that fall within Asset Condition compared to new additions that go through the normal planning process at ISO-NE covering the period 2022-2024, and also for the period of any forecasts for asset condition projects for as many years out as the Company forecasts. This information may be provided in the form of a schedule.

Response:

The total capital additions of Rhode Island Energy owned transmission facilities for the period 2022 to 2026 that fall within Asset Condition are shown in Table 1 below. This table includes actual plant additions for 2022 and 2023 and forecasted additions for 2024, 2025, and 2026. These values include all projects that are not a direct result of system reliability needs caused by changes in system load, generation, or a regional system planning study. Asset Condition projects are driven by a variety of reasons unique to the specific assets being replaced or upgraded including, but not limited to, replacement of degraded assets that have reached end of life due to exposure or damage, upgrading infrastructure consisting of technology that is unreliable or no longer supported by manufacturers, and upgrading infrastructure to meet current North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC) requirements.

All transmission asset condition projects with costs in excess of \$5 million go through a planning process that includes review and consultation with ISO New England (ISO-NE). Asset condition projects associated with Pool Transmission Facilities (PTF) are incorporated into ISO-NE's Regional System Planning (RSP) process in accordance with Attachment K of the ISO-NE Open Access Transmission Tariff (OATT). Additional details on how these projects are incorporated into the RSP process can be found in Section 6.1 of the ISO-NE Transmission Planning Process Guide and Appendix B of the Joint New England Transmission Owner Asset Condition Process Guide. Asset condition projects associated with non-PTF facilities are included in Rhode Island Energy's Local System Plan, which is provided for review to ISO-NE as part of the Local System Planning process described in Appendix 1 to Attachment K of the OATT.

Rhode Island Energy does not file a transmission capital additions forecast with FERC beyond two years from when actuals are available. The transmission formula rate filing is a forward-looking rate using available actual data and two years of forecasted data to calculate an estimated rate. For instance, to set 2025 RNS/LNS rates, the formula rate uses 2023 actuals and 2024 and

Prepared by or under the supervision of: Kyra Lagunilla (as to Table 1, and the 1st, 2nd, and 4th paragraphs of the written response), and
Alexei Spinu (as to 3rd paragraph of the written response)

Record Request No. 5, Page 2

2025 capital additions forecasts. For that reason, New England Transmission Owners (“NETOs”) only provide a two-year forecast of capital additions. The Company has forecasted 2026 transmission capital additions solely for the purpose of the Annual Retail Rate filing in order to provide a more accurate outlook of future rates. Any changes in this period are trued-up in future filings when actuals become available.

Rhode Island Energy’s Asset Condition projects beyond the two-year horizon are captured in the New England Transmission Owner Asset Condition Project Forecast (provided as Attachment RR-5). This forecast is prepared annually and shared with the Planning Advisory Committee (PAC) stakeholders. Projects Under Evaluation and Under Development are in the very early stages, so only a Planning Horizon and Cost Category are available until the project is further developed.

Table 1: Rhode Island Energy Total Asset Condition Driven Capital Additions

	(a)	(b)	(c)	(d)	(e)
	Year	Total In Service Additions (\$M)	Total In Service Additions – non Asset Condition (\$M)	Total In Service Additions - Asset Condition (\$M)	Actual/Forecast
(1)	2022	\$134.1	\$8.9	\$125.1	Actual
(2)	2023	\$41.1	(\$0.4)	\$41.5	Actual
(3)	2024	\$64.5	\$4.9	\$59.6	Forecast
(4)	2025	\$128.8	\$23.2	\$105.7	Forecast
(5)	2026	\$175.7	\$17.1	\$158.6	Forecast

New England Transmission Owner Asset Condition Project Forecast

NOTE: "Under Evaluation" and "Under Development" projects are provided for illustrative purposes only and are not necessarily indicative of actual projects and identified needs.

Project Stages
Developed – Full scope/conceptual cost estimates have been developed and project has been presented to PAC; ISD Year and Estimated Costs available
Under Development – Project planning is underway; project scope and conceptual cost estimates are currently being developed; Cost Category information available
Under Evaluation – Currently being evaluated for possible asset condition project, but no formal scope/cost estimates have been developed; Planning Horizon information available

Project Stage	ACL ID	Line Number or Substation Name	kV	Primary Equipment Owner	State	Current Asset Condition	Anticipated Solution	Developed Projects				Under Development		
								PAC Presentation Date	Status (Concept, Proposed, Planned, Under Construction)	Estimated Cost	Estimated ISD	Anticipated PAC Presentation Date	Cost Category	Planning Horizon
Developed	150	315	345	Rhode Island Energy	RI	Degradation of poles, towers, and/or shield wire.	Replace poles, towers and shield wire	Feb 2019	Under Construction	\$ 25,107,000	2024			
Developed	335	L-190 & G-1855	115	Rhode Island Energy	RI	Degradation of poles, towers, shield wire, and/or conductor. NPCC Directory # 1 Protection Modification - Phase 5	Replace poles, towers, shield wire, and conductor.	Jul 2022	Under Construction	\$ 8,493,000	2024			
Developed	99	R-144, Q-1435, & V-148N	115	Rhode Island Energy	RI	NPCC Directory # 1 Protection Modification - Phase 4.	Upgrade line protection to dual high speed systems.	Dec 2017	Concept	\$ 5,100,000	2025			
Developed	430	E-183W	115	Rhode Island Energy	RI	Degradation of poles, towers, shield wire, and/or conductor.	Replace poles, towers, shield wire, and conductor.	Oct 2023	Proposed	\$ 10,600,000	2026			
Developed	426	171N, T-172N, S-171S, & T-172	115	Rhode Island Energy	RI	Degradation of poles, towers, shield wire, and/or conductor.	Replace targeted poles, towers, shield wire, and conductor.	Oct 2023	Planned	\$ 10,400,000	2026			
Developed	427	171N, T-172N, S-171S, & T-172	115	Rhode Island Energy	RI	Degradation of poles, towers, shield wire, and/or conductor.	Replace targeted poles, towers, shield wire, and conductor.	Oct 2023	Planned	\$ 10,400,000	2026			
Under Development	N/A	REDACTED	EDACTED	Rhode Island Energy	RI	Insufficient security, unmonitored assets	Upgrade security perimeter, install interior lighting, install equipment monitoring					TBD	Group 1: \$0-10M	2 Year
Under Development	N/A	1870S	115	Rhode Island Energy	RI	Aging conductor and shieldwire, and degradation of poles.	Replace poles, shield wire, and conductor.					TBD	Group 3: \$25-100M	3-5 Year
Under Development	N/A	H17	115	Rhode Island Energy	RI	Aging wood poles	Replace wood poles					TBD	Group 1: \$0-10M	3-5 Year
Under Evaluation	N/A	1870	115	Rhode Island Energy	RI	Aging line, wood poles	Full rebuild or targeted refurbishment					TBD	TBD	3-5 Year
Under Evaluation	N/A	1870N	115	Rhode Island Energy	RI	Aging line, wood poles	Full rebuild or targeted refurbishment					TBD	TBD	3-5 Year
Under Evaluation	N/A	332	345	Rhode Island Energy	RI	Aging line with deteriorating wood poles	Full rebuild or targeted refurbishment					TBD	Group 3: \$25-100M	3-5 Year
Under Evaluation	N/A	347	345	Rhode Island Energy	RI	Aging line with deteriorating wood poles	Full rebuild or targeted refurbishment					TBD	Group 3: \$25-100M	3-5 Year
Under Evaluation	N/A	Q-143	115	Rhode Island Energy	RI	Aging conductor and shieldwire, and degradation of poles.	Full rebuild or targeted refurbishment					TBD	Group 2: \$10-25M	3-5 Year
Under Evaluation	N/A	R-144N	115	Rhode Island Energy	RI	Aging conductor and shieldwire, and degradation of poles.	Full rebuild or targeted refurbishment					TBD	Group 2: \$10-25M	3-5 Year
Under Evaluation	N/A	Franklin Square/Manchester St	115	Rhode Island Energy	RI	Aging relays, substation infrastructure	Relay Upgrades					TBD	Group 3: \$25-100M	3-5 Year
Under Evaluation	N/A	V-148N	115	Rhode Island Energy	RI	Aging line	Full rebuild or targeted refurbishment					TBD	TBD	6-10 Year
Under Evaluation	N/A	R9	115	Rhode Island Energy	RI	Aging line	Full rebuild or targeted refurbishment					TBD	TBD	6-10 Year
Under Evaluation	N/A	West Kingston	115	Rhode Island Energy	RI	Aging relays	Relay Upgrades / new transmission control cubicle					TBD	TBD	6-10 Year
Under Evaluation	N/A	Kenyon	115	Rhode Island Energy	RI	Aging relays	Relay Upgrades / new transmission control cubicle					TBD	TBD	6-10 Year
Under Evaluation	N/A	Wood River	115	Rhode Island Energy	RI	Aging relays	Relay Upgrades / new transmission control cubicle					TBD	TBD	6-10 Year
Under Evaluation	N/A	Staples	115	Rhode Island Energy	RI	Aging relays	Relay Upgrades / new transmission control cubicle					TBD	TBD	6-10 Year
Under Evaluation	N/A	Valley Sub	115	Rhode Island Energy	RI	Aging relays	Relay Upgrades / new transmission control cubicle					TBD	TBD	6-10 Year
Under Evaluation	N/A	E-105	115	Rhode Island Energy	RI	Aging equipment and equipment failures	Full rebuild or targeted refurbishment					TBD	TBD	TBD
Under Evaluation	N/A	F-106	115	Rhode Island Energy	RI	Aging equipment and equipment failures	Full rebuild or targeted refurbishment					TBD	TBD	TBD

Record Request No. 6

Request:

Explain what is going on with All American Foods and Orbit Energy in Attachment PUC 1-15 on pages 2-3; provide a full breakout for these two-line items by month and explain actual market value.

Response:

In Attachment PUC 1-15, the Company reported that it received an energy market payment of \$807 in the month of August 2024 attributable to *All American Foods*.¹ Upon further investigation, the Company has determined that, for the month of August 2024 only, there was an error in the transposition of data for energy market payments used in the 2024 Long-Term Contracting for Renewable Energy Recovery ("LTCRER") program reconciliation that resulted in the incorrect recording of energy market payments for this asset as well as others. The result of this error was an over-statement of \$1.6 million in energy market payments included in the 2024 LTCRER program reconciliation. As corrected, the energy market payments, which are an offset to the total cost of the program, are \$1.6 million lower than originally presented; consequently, the correction of this error results in a \$1.6 million increase in the 2024 under-recovery of the LTCRER program as compared to the Company's original filing. Due to the timing constraints associated with the discovery of this error, the Company *is not* proposing to change the LTCRER Reconciliation Factor in effect as of April 1, 2025. Instead, the Company proposes to carry forward the \$1.6 million under-recovery amount, *excluding interest*, and include it as a part of the beginning balance, as of January 2025, of the 2025 LTCRER program reconciliation.

Please refer to Attachment RR-6 for the requested detail for 2024 with respect to *All American Foods* and *Orbit Energy*.

Although *All American Foods* is listed as an active generation facility, the actual MWh output demonstrates that the unit did not produce generation in 2024, thereby resulting in the actual contract cost of \$0.00 as shown in Attachment PUC 1-15, page 2 of 5, Column (i), Line (17). As discussed above, the originally recorded Energy Market Value of \$807 attributed to *All American Foods* was in error; its actual Energy Market Value for 2024 was \$0, as shown in Attachment RR-6, Column (b), Line (13). The Company would further note that this facility is a "Unit

¹ Please refer to Attachment PUC 1-15, Page 3 of 5, Column (b), Line (17).

Record Request No. 6, Page 2

Contingent project,” which means that the facility has no obligation to deliver energy or Renewable Energy Certificates (“RECs”) if it is not operating and producing energy. The Company has contacted the facility owner to determine its status. *All American Foods* has not yet responded to the Company’s inquiry.

Orbit Energy is listed as an active generation facility and recorded 87.6 MWh in sales to the Company in May 2024, as shown in Attachment RR-6, Column (a), Line (18).² This MWh value equates to a total market value of \$17,540.³ *Orbit Energy* is also a “Unit Contingent project” such that the facility has no obligation to deliver energy or RECs if it is not operating and producing energy. The Company presently understands that *Orbit Energy*’s lack of generation is associated with the fact that it is seeking to combine its Load Service and Generation Service. *Orbit Energy* is in ongoing discussions with the Company to complete this process.

In the months of January 2024 and April 2024, the Company received resettlements for *Orbit Energy* for energy market payments associated with generation in prior periods.⁴ The Company would note that energy market payment resettlements associated with generation in prior periods are not uncommon.

Please note that the Company is filing, under separate cover and for informational purposes only, versions of the Company’s Schedule NECO-1, Schedule NECO-17, and Schedule NECO-18, that reflect the correction of the error identified above. Likewise, the Company is contemporaneously resubmitting responses to certain data requests contained in the Commission’s First Set of Data Requests to reflect the correction of the error. As discussed above, however, the Company *is not* proposing to change the LTCRER Reconciliation Factor in effect as of April 1, 2025, but instead proposes to carry forward the \$1.6 million under-recovery amount associated with the error, *excluding interest*, and include it as a part of the beginning balance, as of January 2025, of the 2025 LTCRER program reconciliation.

² Please refer also to Attachment PUC 1-15, Page 3 of 5, Column (a), Line (30).

³ Please note that, while the Company knows the exact the Energy Market Value and Capacity Market value associated with each facility, it records REC proceeds on an aggregate basis such that it can only estimate the REC Market Value associated with a facility based on that facility’s share of total LTCRER program output.

⁴ Please refer to Attachment RR-6, column (b), Lines (14) and (17).

Long-Term Contracting for Renewable Energy Recovery (LTCRER)
Actual Market Value
For the Period January 2024 through December 2024

Actual Market Value

	<u>Unit</u>	<u>Month</u>	Actual MWh Purchased <u>Under Contracts</u> (a)	Energy Market <u>Value</u> (b)	REC Market <u>Value</u> (c)	<u>Capacity</u> (d)	Total Market <u>Value</u> (e)	<u>Total REC</u> (f)
(1)		Jan-24	0.0	\$0	\$0	\$0	\$0	
(2)		Feb-24	0.0	\$0	\$0	\$0	\$0	
(3)		Mar-24	0.0	\$0	\$0	\$0	\$0	
(4)		Apr-24	0.0	\$0	\$0	\$0	\$0	
(5)		May-24	0.0	\$0	\$0	\$0	\$0	
(6)	All American Foods Solar Asset. No. 46721	Jun-24	0.0	\$0	\$0	\$0	\$0	
(7)		Jul-24	0.0	\$0	\$0	\$0	\$0	
(8)		Aug-24	0.0	\$0	\$0	\$0	\$0	
(9)		Sep-24	0.0	\$0	\$0	\$0	\$0	
(10)		Oct-24	0.0	\$0	\$0	\$0	\$0	
(11)		Nov-24	0.0	\$0	\$0	\$0	\$0	
(12)		Dec-24	0.0	\$0	\$0	\$0	\$0	
(13)		Total	0.0	\$0	\$0	\$0	\$0	0.00%
(14)		Jan-24	0.0	\$1,774	\$0	\$0	\$1,774	
(15)		Feb-24	0.0	\$0	\$0	\$0	\$0	
(16)		Mar-24	0.0	\$0	\$0	\$0	\$0	
(17)		Apr-24	0.0	\$707	\$0	\$0	\$707	
(18)	Orbit Energy Asset No. 50057	May-24	87.6	\$4,868	\$3,788	\$6,403	\$15,059	
(19)		Jun-24	0.0	\$0	\$0	\$0	\$0	
(20)		Jul-24	0.0	\$0	\$0	\$0	\$0	
(21)		Aug-24	0.0	\$0	\$0	\$0	\$0	
(22)		Sep-24	0.0	\$0	\$0	\$0	\$0	
(23)		Oct-24	0.0	\$0	\$0	\$0	\$0	
(24)		Nov-24	0.0	\$0	\$0	\$0	\$0	
(25)	Dec-24	0.0	\$0	\$0	\$0	\$0		
(26)		Total	87.6	\$7,349	\$3,788	\$6,403	\$17,540	0.01%

- (a) per PUC 1-15 (Corrected) Page 2, Column (d)
- (b) per Company Accounting records
- (c) Column (f) x \$25,738,374, total REC value received in 2024
- (d) per Company Accounting records
- (e) Column (b) + Column (c) + Column (d)
- (f) Column (a) / 595,426 (total MWh generated in 2024)

Record Request No. 7

Request:

For the customer account referenced in the Company's response to PUC 1-7 please indicate: (a) the number of off takers and their respective customer group(s); (b) whether there was a communication sent to satellite accounts regarding reversal of prior bill credits; (c) whether any customer complaints were received as a result; and (d) the number of such customer complaints received. If there were any other similarly situated accounts, please answer the same questions for all of those.

Response:

- a) There were 39 off takers related to this host customer at the time of the credit issue.

A16	17
C06	8
G02	11
G32	3
Grand Total	39

- b) Bills reflecting incorrect bill credits as a result of the erroneous meter data were never sent to the host customer. The bills were prepared, but never issued. A communication was not sent to the affected customers who received the transfers from the host account.
- c) There were no complaints received by the Company as a result of the reversal of bill credits from customers whose bills reflecting credits were subsequently reversed.
- d) The Company is not presently aware of similar situated accounts.

Record Request No. 8

Request:

Please provide a narrative explanation of what caused the MV90 issues with respect to the customer referenced in the Company's response to data request PUC 1-7 and provide the original and corrected data set of the meter data for the customer.

Response:

The customer referenced in the Company's response to PUC 1-7 was interconnected to the Company's system as of June 11, 2024. From the June 11, 2024 interconnection date until the August 19, 2024 billing system cutover date, this account did not bill on National Grid's billing system. After the August 19, 2024 system cutover, this account did not bill on Rhode Island Energy's billing system until October 2024. Post cutover, the Company investigated the cause for this account to be in "No Bill" status and determined that the meter interval data for July 10, 2024, was incorrect (i.e., it was too high). The Company believes that the incorrect meter data from July 10, 2024, resulted in a billing exception in National Grid's billing system, such as a high-low bill, that caused the account to be in "No Bill" status at National Grid. The incorrect meter data from July 10, 2024, was transferred to Rhode Island Energy as part of the billing system cutover on August 19, 2024, and the account continued to be in "No Bill" status. During its investigation of this account, the Company obtained the actual meter interval data for July 10, 2024. The original (incorrect) net read for the bill period of July 10 through August 12, 2024, was 38,244,120 kWh; the corrected net read for the bill period of July 10 through August 12, 2024, was 642,497 kWh.

Record Request No. 9

Request:

With respect to the customer referenced in the Company's response to PUC 1-7, what is the number of kWh that the facility generated and was it resettled at ISO-NE? Please provide the customer's asset identification on NEPOOL GIS.

Response:

The ISO-NE asset ID for this customer is 73814. Initial settlement for this asset was 990,288 kWh in July (which was submitted by National Grid) and 511,388 kWh in August (submitted by National Grid from August 1 to 15 and by Rhode Island Energy August 16 to 31). No resettlements were submitted to ISO-NE for either July or August. Rhode Island Energy has submitted a Meter Data Error RBA (Requested Billing Adjustment) to ISO-NE for August to resubmit data for all assets which meet the RBA settlement threshold, which is greater than or equal to 1,000 MWh during a calendar month. Asset 73814 does not meet the threshold to qualify for the August RBA.

The Narragansett Electric Company
d/b/a Rhode Island Energy
RIPUC Docket No. 25-04-EL
In Re: 2025 Annual Retail Rate Filing
Responses to Record Requests
Issued at the Commission’s Evidentiary Hearing
On March 20, 2025

Record Request No. 10

Request:

Please provide the percentage of Pennsylvania customers who participate in budget billing and explain the differences between Rhode Island and Pennsylvania budget billing programs that might explain any differences in enrollment.

Response:

Please see the table below for the requested information.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
(1)	PPL PA Budget Bill Participation Percentage	2024-08	2024-09	2024-10	2024-11	2024-12	2025-01	2025-02	2025-03
(2)	RESIDENTIAL ELECTRIC	1.96%	2.09%	2.31%	2.40%	2.47%	2.57%	2.68%	2.75%
(3)	NON- RESIDENTIAL ELECTRIC	0.21%	0.23%	0.25%	0.25%	0.25%	0.25%	0.25%	0.27%

The Rhode Island and the Pennsylvania Budget Bill programs have very similar eligibility criteria. The only difference is that the Pennsylvania customers that are enrolled in OnTrack Program (Percent of Income, Low Income Program), are not able to enroll in the Pennsylvania Budget Bill program. Rhode Island Energy customers enrolled in the Discount Rate are able to enroll in the Rhode Island Budget Bill program.

Record Request No. 11

Request: Please supply the same data provided for the Company’s response to PUC 2-1(c) for gas customers.

Response: Please see the table below detailing Gas Budget Bill customers.

Gas Residential Non Heat			
	MONTH	RATE	MONTHLY TOTALS
1	202403	1012	212
2	202404	1012	242
3	202405	1012	243
4	202406	1012	238
5	202407	1012	240
6	202408	1012	247
7	202409	1012	257
8	202410	1012	273
9	202411	1012	290
10	202412	1012	310
11	202501	1012	326
12	202502	1012	349

Gas Residential Low Inc Non Heat			
	MONTH	RATE	MONTHLY TOTALS
1	202403	1101	21
2	202404	1101	22
3	202405	1101	23
4	202406	1101	21
5	202407	1101	26
6	202408	1101	27
7	202409	1101	30
8	202410	1101	36
9	202411	1101	39
10	202412	1101	41
11	202501	1101	43
12	202502	1101	45

Gas Residential Heat			
	MONTH	RATE	MONTHLY TOTALS
1	202403	1247	18653
2	202404	1247	19929
3	202405	1247	19835
4	202406	1247	19614
5	202407	1247	19520
6	202408	1247	19722
7	202409	1247	20035
8	202410	1247	20410
9	202411	1247	20796
10	202412	1247	21043
11	202501	1247	21426
12	202502	1247	22113

Gas Residential Low Inc Heat			
	MONTH	RATE	MONTHLY TOTALS
1	202403	1301	1431
2	202404	1301	1479
3	202405	1301	1477
4	202406	1301	1474
5	202407	1301	1453
6	202408	1301	1497
7	202409	1301	1566
8	202410	1301	1625
9	202411	1301	1709
10	202412	1301	1767
11	202501	1301	1860
12	202502	1301	1984