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Rhode Island Energy™
a PPL company

February 20, 2024

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 23-48-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan
Responses to PUC Data Requests – Set 6

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's responses to the Public Utilities Commission's ("PUC") Sixth Set of Data Requests in the above-referenced matter.

Thank you for your attention to this transmittal. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 23-48-EL Service List

PUC 6-1

Request:

Referring to the accompanying Excel worksheet (separate attachment to the issuing email):

a. Please confirm the values and calculations in the worksheet are correct.

b. Please update line 15, Budget FY 2024 to reflect the most recent FY 2024 forecast values.

Response:

a. The values are correct except for line 5, FY 2026 Current RIE Forecast of Damage/Failure. The value has been updated from $17,813,000 to $17,616,000 to align with Bates page 84. The cells referencing this cell have been updated and highlighted on Attachment PUC 6-1.

b. Line 15 has been updated with the FY 2024 forecast from the FY 2024 Q3 Report on Attachment PUC 6-1.

Prepared by or under the supervision of: Kathy Castro

23-48-EL RIE FY 2025 Electric ISR

REVISED and UPDATED Comparison of RIE Current Forecast to National Grid's Last ISR Forecast for FY25-FY27

US$(000) *(Forecast Sources: Attachment 3 from Docket 5209 & Current filing)*

		Cust Req/Public Req	Damage Failure	Asset Condition	Non-Infrastructure	System Cap & Perf	TOTAL
1	FY 2025 - Ngrid Docket 5209 Forecast	27,789	14,180	49,598	1,436	18,996	111,999
2	FY 2025 - Current RIE Forecast	32,862	17,813	51,045	892	38,303	140,915
3	**Difference**	**5,073**	**3,633**	**1,447**	**(544)**	**19,307**	**28,916**
4	FY 2026 - Ngrid Docket 5209 Forecast	28,293	14,465	47,536	1,537	21,170	113,001
5	FY 2026 - Current RIE Forecast	31,399	17,616	67,898	799	67,321	185,033
6	**Difference**	**3,106**	**3,151**	**20,362**	**(738)**	**46,151**	**72,032**
7	FY 2027 - Ngrid Docket 5209 Forecast	28,809	14,753	45,555	266	24,617	114,000
8	FY 2027 - Current RIE Forecast	31,728	16,024	79,109	737	60,678	188,276
9	**Difference**	**2,919**	**1,271**	**33,554**	**471**	**36,061**	**74,276**
10	Ngrid Docket 5209 3 yr Forecast Avg (FY 25- 27)	28,297	14,466	47,563	1,080	21,594	113,000
11	Current RIE 3 yr Forecast Avg (FY 25-27)	31,996	17,151	66,017	809	55,434	171,408
12	**Difference**	**3,699**	**2,685**	**18,454**	**(270)**	**33,840**	**58,408**
13	Actual FY 2022	34,335	20,200	35,792	1,100	15,303	106,730
14	Actual FY 2023	31,727	17,461	44,239	1,554	13,464	108,445
15	*Forecast FY 2024 - Q3 Report*	32,569	20,547	52,552	562	17,810	124,040
16	3-Year Historical Avg (FY22-FY24)*	32,877	19,403	44,194	1,072	15,526	113,072
17	**Difference from Current (line 11 - line 16)**	**(881)**	**(2,252)**	**21,823**	**(263)**	**39,908**	**58,336**
18	NGrid Total Cap Spend Forecast 3-Yr (FY 25-27)	84,891	43,398	142,689	3,239	64,783	339,000
19	Current RIE Total Cap Spend Forecast 3-Yr (FY 25-27)	95,989	51,453	198,052	2,428	166,302	514,224
20	**Difference**	**11,098**	**8,055**	**55,363**	**(811)**	**101,519**	**175,224**

* Historical Average Calculated from Attachment 1, Section 2 , Bates page 79.

PUC 6-2

Request:

Referring to the accompanying Excel worksheet, the value in **Asset Condition**, Line 20, of $55.4 million represents the difference in 3 year forecasts of Capital Spend for Fiscal Years 2025 through 2027 as presented in Docket 5209 and the instant docket.

a. Please explain the reason(s) for the difference in the 3 year forecasts.

b. Please thoroughly explain any difference in Asset Condition investment strategy or philosophy between National Grid and PPL for Narragansett Electric-Electric Operations that contribute to the variance.

Response:

a. Please see the table on Attachment PUC 6-2. Reason codes shown in column (n) are explained below.

   (a) Centredale Substation and Division St. Transformers - one year delay in start date resulted in realignment of cash flows within the portfolio. The Northwest RI and Central RI West area studies were revised in September 2022 to update the cash flows which resulted in increases in total project costs.
   (b) Phillipsdale Substation and Apponaug Substation - one year delay in start date resulted in realignment of cash flows within the portfolio. The FY 2023 Plan assumed a FY 2024 start date. Similar total project costs.
   (c) Providence Study Ph 1B, 2 and 4 - projects have experienced delays due to resource availability and work was deferred. Additional spending was required as described in the FY 2022 quarterly reports.
   (d) Spare Transformers, Breakers, Regulators and Bushing - to ensure availability of substation equipment due to increased lead times and deficient spare transformer inventory levels. Please also see the Company's response to Division 2-3.
   (e) Asset Replacement Blanket Projects - replacement of secondary cable sections and inflation. See the Company's response to PUC 3-13.
   (f) Various Programs – refinement of specific projects within the programs and prioritize of program work within the portfolio to allow for other work and maintain affordability.
   (g) Reserves and Area Study Projects - the reserves included in the FY 2023 Five Year Budget were a placeholder for projects originating from area studies not specifically identified in the Five Year Budget. The FY 2025 Five Year Budget includes the more defined projects and the proposed cash flows as opposed to an estimate.

Prepared by or under the supervision of: Kathy Castro

PUC 6-2, page 2

b. No portion of the variance is attributable to a difference in Asset Condition investment strategy or philosophy between National Grid and PPL for Narragansett Electric-Electric Operations..

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
		Docket 5209 - FY 2023 ISR Plan				Docket 23-48-EL - FY 2025 ISR Plan Proposal				Change				Reason
		FY 2025 Forecast	FY 2026 Forecast	FY 2027 Forecast	Total (Line 18)	FY 2025 Forecast	FY 2026 Forecast	FY 2027 Forecast	Total (Line 19)	FY 2025 Forecast	FY 2026 Forecast	FY 2027 Forecast	Total (Line 20)	
1	Centredale Substation	2,328	2,607	864	**5,799**	500	3,007	2,725	**6,232**	(1,828)	400	1,861	**433**	a
2	Division St Transformers	1,320	2,048	-	**3,368**	500	1,494	2,986	**4,980**	(820)	(554)	2,986	**1,612**	a
3	Dyer Street Substation	-	-	-	-	15	-	-	**15**	15	-	-	**15**	--
4	Phillipsdale Substation	3,935	4,290	4,490	**12,714**	200	6,208	7,810	**14,218**	(3,735)	1,918	3,320	**1,504**	b
5	Prov Study-Ph1B–Admiral St Substation	9,546	523	-	**10,069**	14,983	3,680	-	**18,663**	5,437	3,157	-	**8,594**	c
6	Prov Study-Ph2–Harris/Olneyville/Rochambeau D Line	6,033	10,002	7,064	**23,099**	2,922	9,400	7,064	**19,386**	(3,111)	(602)	-	**(3,713)**	c
7	Prov Study-Ph4–Knightsville Substation	3,101	254	-	**3,355**	7,990	-	-	**7,990**	4,889	(254)	-	**4,635**	c
8	Apponaug Substation	1,070	2,510	2,510	**6,090**	200	1,195	2,015	**3,410**	(870)	(1,315)	(495)	**(2,680)**	b
9	Spare Transformer				-	540	1,620	3,240	**5,400**	540	1,620	3,240	**5,400**	d
10	Spare Breakers				-	-	440		**440**	-	440	-	**440**	d
11	Spare Regulators				-	96			**96**	96	-	-	**96**	d
12	Spare Bushings				-	100			**100**	100	-	-	**100**	d
13	Battery Replacement	400	400	400	**1,200**	195	387	319	**901**	(205)	(13)	(81)	**(299)**	f
14	Blanket Projects	5,287	5,352	5,417	**16,056**	6,177	6,338	6,504	**19,019**	890	986	1,087	**2,963**	e
15	I&M	3,000	3,000	3,000	**9,000**	1,530	1,530	1,530	**4,590**	(1,470)	(1,470)	(1,470)	**(4,410)**	f
16	URD Program	5,500	5,600	5,700	**16,800**	5,000	5,411	5,723	**16,134**	(500)	(189)	23	**(666)**	f
17	Other Asset Replacement	200	-	-	**200**				-	(200)	-	-	**(200)**	f
18	UG Cable Replacement program	4,000	4,250	4,500	**12,750**	5,500	6,000	6,000	**17,500**	1,500	1,750	1,500	**4,750**	f
19	UG Improvements	700	700	-	**1,400**	700	565	-	**1,265**	-	(135)	-	**(135)**	f
20	Reserves - AR	3,178	6,000	11,610	**20,788**	-	1,000	1,000	**2,000**	(3,178)	(5,000)	(10,610)	**(18,788)**	g
21	Other Area Study Projects													g
22	- Blackstone Valley South	-	-	-	-	781	1,556	2,457	**4,794**	781	1,556	2,457	**4,794**	g
23	- Central RI West	-	-	-	-	1,383	4,823	7,210	**13,417**	1,383	4,823	7,210	**13,417**	g
24	- East Bay	-	-	-	-	-	25	-	**25**	-	25	-	**25**	g
25	- Newport	-	-	-	-	1,166	7,430	14,333	**22,929**	1,166	7,430	14,333	**22,929**	g
26	- Providence	-	-	-	-	492	5,396	7,407	**13,295**	492	5,396	7,407	**13,295**	g
27	- Tiverton	-	-	-	-	75	393	786	**1,254**	75	393	786	**1,254**	g
28	**Asset Condition Total**	**49,598**	**47,536**	**45,555**	**142,689**	**51,045**	**67,898**	**79,109**	**198,052**	**1,446**	**20,363**	**33,554**	**55,363**	

PUC 6-3

Request:

Please provide a forecast of actual spending for FY 2024, compared to the approved budget. Please create a schedule showing this by spending category similar to what is provided in Attachment 3 on Bates pages 84-86.

Response:

Please See Attachment PUC 6-3 for the FY 2024 forecasted spending included in the Company's FY 2024 Third Quarter Update filed on February 15, 2024.

Prepared by or under the supervision of: Kathy Castro

Line Number	Spending Rationale and Category	ISR Grouping	Docket 22-53-EL FYTD Actuals 12/31/23	Docket 22-53-EL Preliminary FY 2024 Q3 Forecast	Docket 22-53-EL FY 2024 Budget
1	**Customer Request/Public Requirements**				
2		New Business - Commercial	8,745	11,025	9,093
3		New Business - Residential	5,471	7,212	7,212
4		Public Requirements	1,953	1,249	1,249
5		Transformers and Related Equipment	6,776	8,350	5,000
6		Meters and Meter Work	1,036	2,089	2,605
7		Distributed Generation	5,781	1,000	1,000
8		Third Party Attachments	(732)	331	280
9		Land and Land Rights	329	500	500
10		Outdoor Lighting	353	813	575
11	**Total Customer Request/Public Requirements**		29,711	32,568	27,514
12	**Damage Failure**				
13		Damage /Failure	9,920	12,545	10,940
14		Reserves	-	-	979
15		Failed Assets	2,619	4,340	1,323
16		Storms	3,176	3,662	1,950
17	**Total Damage Failure**		15,716	20,547	15,192
18	**Total Non-Discretionary**		**45,427**	**53,116**	**42,706**

Line Number	Spending Rationale and Category	ISR Grouping	Docket 22-53-EL FYTD Actuals 12/31/23	Docket 22-53-EL Preliminary FY 2024 Q3 Forecast	Docket 22-53-EL FY 2024 Budget
1	**Asset Condition**				
2	**Major Projects**	Dyer Street Substation (D Sub + D Line)	1,861	2,553	-
3		Admiral St 12kV Substation	195	3,673	2,784
4		Kingston Equipment Replacement	96	96	-
5		Phillipsdale Substation	-	-	-
6		Southeast Substation	327	327	66
7	**Other**	Underground Cable Replacement	4,231	4,281	5,500
8		URD Cable Replacement	5,321	6,496	6,276
9		Blanket Projects	4,298	5,686	5,220
10		I&M	257	476	3,000
11		Substation Breakers & Reclosers	1,231	1,231	437
12		Other Area Study Projects - BSVS	1,058	1,058	-
13		Other Area Study Projects - CRIE	27	27	-
14		Other Area Study Projects - CRIW	-	-	-
15		Other Area Study Projects - East Bay	-	-	-
16		Other Area Study Projects - Newport	98	98	-
17		Other Area Study Projects - NWRI	135	135	-
18		Other Area Study Projects - Providence	-	-	-
19		Other Area Study Projects - SCW	-	-	-
20		Tiverton Substation	60	60	-
21		Providence Area LT Supply & Distrib Study	17,491	22,110	21,530
22		Reserve	-	-	-
23		Batteries / Chargers	31	227	230
24		Recloser Replacements	1,209	1,209	1,300
25		UG Improvements and Other	2,732	2,809	1,383
26	**Total Asset Condition**		40,656	52,552	47,726
27	**Non-Infrastucture**				
28		General Equip & Telecom Blanket	(805)	536	700
29		Verizon Copper to Fiber	11	26	1,000
30	**Total Non-Infrastructure**		**(793)**	**562**	**1,700**

Line Number	Spending Rationale and Category	ISR Grouping	Docket 22-53-EL FYTD Actuals 12/31/23	Docket 22-53-EL Preliminary FY 2024 Q3 Forecast	Docket 22-53-EL FY 2024 Budget
1	**System Capacity & Performance**				
2		Aquidneck Island	1,189	1,327	1,038
3		New Lafayette Substation	197	361	750
4		Warren Substation	1,915	2,381	1,969
5		Nasonville Substation (D Sub + D Line)	1,346	2,338	1,912
6		East Providence Substation	720	976	1,330
7		Weaver Hill Road Substation	419	665	1,507
8		3V0	201	217	1,095
9		EMS/RTU	(15)	(15)	658
10		Overloaded Transformer Replcmts	1,118	1,500	1,500
11		Blanket Projects	5,209	5,639	2,490
12		Other Area Study Projects - BSVS	120	120	400
13		Other Area Study Projects - CRIW	366	845	1,371
14		Other Area Study Projects - East Bay	-	-	-
15		Other Area Study Projects - Newport	-	-	-
16		Other Area Study Projects - NWRI	775	1,185	1,933
17		Other Area Study Projects - SCE	-	-	-
18		Other Area Study Projects - SCW	101	137	364
19		Tiverton D-Line	130	130	109
20		Reserve	-	-	-
21		CEMI-4	1,072	1,221	1,230
22		ERR	-	-	-
23		Distrib Automation Recloser Program	-	-	-
24		ADMS/DERMS Advanced	-	-	-
25		DER Monitor/Manage	-	-	-
26		Electromech RelayUpgrades	-	-	-
27		Fiber Network	-	-	-
28		VVO - Smart Capacitors and Regulators	235	235	-
29		Mobile Substation	-	-	-
30		Other projects and programs	(1,688)	(1,451)	541
31	**Total System Capacity & Performance**		**13,409**	**17,810**	**20,197**
32	**Total Advanced Metering Functionality (AMF)**		**-**	**-**	**-**
33	**Total Discretionary**		**53,273**	**70,924**	**69,623**
34	**Total Capital Spending including AMF**		**98,699**	**124,040**	**112,329**
35	**Total Capital Spending excluding AMF**		**98,699**	**124,040**	**112,329**

PUC 6-4

Request:

Please provide the following:

a. A schedule with a list of all the separately tracked major projects that were identified as being within the asset condition category for which capital spending occurred in each ISR fiscal year from FY 2022 through forecasted spending in FY 2024, and indicate the total amount of actual spending on each of those major projects within those respective fiscal years;

b. A schedule with a list of all the separately tracked major projects that were identified as being within the system capacity & performance category for which capital spending occurred in each ISR fiscal year from FY 2022 through forecasted spending in FY 2024, and indicate the total amount of actual spending on each of those major projects within those respective fiscal years; and

c. If there were any separately tracked major projects that were not identified in either the asset condition category or the system capacity & performance category in any of the ISR fiscal years from FY 2022 through forecasted spending in FY 2024, please identify them in a separate schedule and indicate the total amount of actual spending on each of those major projects within those respective fiscal years.

Response:

a. Please see Attachment PUC 6-4 for a list of Asset Condition projects with Budget, Actual and Forecasted capital spending in FY 2022, FY 2023, and FY 2024.

b. Please see Attachment PUC 6-4 for a list of System Capacity & Performance projects with Budget, Actual and Forecasted capital spending in FY 2022, FY 2023, and FY 2024.

c. There were no separately tracked major projects that were not identified in either the asset condition category or the system capacity & performance category in any of the ISR fiscal years from FY 2022 through forecasted spending in FY 2024.

Prepared by or under the supervision of: Kathy Castro

(a) **Asset Condition Separately Tracked Projects**

$000's	FY2022 Budget	FY2022 Actuals	FY2023 Budget	FY2023 Actuals	FY2024 Budget	FY2024 Actuals	FY2024 Forecast
Southeast Substation	$2,082	$2,925	$223	$787	$66	$327	$327
Dyer Street Substation	$9,717	$5,135	$3,500	$10,877	$0	$1,861	$2,553
Providence Study Projects - Phase 1A	$4,966	$4,485	$1,484	$1,718	$0	$201	$201
Providence Study Projects - Phase 1B	$2,895	$2,793	$16,585	$5,992	$13,941	$11,115	$15,106
Providence Study Projects - Phase 2	$0	$0	$300	$14	$1,597	$68	$1,642
Providence Study Projects - Phase 4	$492	$175	$1,217	$1,480	$8,776	$6,302	$8,834

(b) **System Capacity & Performance Separately Tracked Projects**

$000's	FY2022 Budget	FY2022 Actuals	FY2023 Budget	FY2023 Actuals	FY2024 Budget	FY2024 Actuals	FY2024 Forecast
East Providence Substation	$731	$278	$2,495	$461	$1,330	$720	$976
Warren Substation	$621	$185	$1,824	$372	$1,969	$1,915	$2,381

PUC 6-5

Request:

Please explain why the "PH2-ProvStudy Geneva, Olnyville, Rhocham4kV project shown in PUC 3-10 should not be treated as a major project for budgeting purposes.

Response:

The Providence Study Phase 2 – Geneva, Olnyville, Rochambeau 4 KV Conversion project involves converting and retiring the 4.16kV load from the Geneva, Olneyville and Rochambeau Avenue substations for 12.47kV operation. The 20 distribution line work requests progress on separate schedules. Due to the number of feeders involved and dependencies, the preliminary engineering, detailed engineering, and resource procurement will not occur simultaneously, so the total project will not reach the Construction Resource Procurement stage at one time, which is a key driver of how separately tracked major projects will be treated for budgeting purposes and evaluated.

Prepared by or under the supervision of: Kathy Castro

PUC 6-6

Request:

Why are the spare transformers categorized as Asset Condition?

Response:

The Asset Condition category is meant for projects or equipment that will reduce the risk and consequences of unplanned failures of transmission and distribution assets. The Company believes that spare transformers have a direct impact at minimizing the consequences of a substation power transformer failure because they enable the Company to quickly replace the failed transformer and return the system to a normal operating configuration. Without a spare transformer, the system would be in an abnormal configuration for 2-3 years while the Company awaits the availability of a replacement transformer, resulting in an increased risk of power quality degradation and exposing a greater number of customers to outages because feeders will be physically longer.

PUC 6-7

Request:

Where are the spare transformers included in Electric Capital Plan in Book 1 on Bates pages 84-86?

Response:

The spare transformers are included on Bates page 85, Line 11, Substation Breakers & Reclosers. The Company notes that the description does not correctly describe the projects included in the line item and should be renamed Substation Spares. Substation Spares is described on Bates page 68 and the individual projects are also shown in Attachment 2, Bates page 81, lines 31 through 33.

Prepared by or under the supervision of: Kathy Castro

PUC 6-8

Request:

Referencing DIV-2-2 (corrected), page 1, the middle paragraph describes 21 groups requiring one spare transformer, two groups requiring two spares, and two groups requiring three. Please confirm this adds up to 31 spares.

Response:

The table shown in DIV-2-2 (corrected), page 1, reflects 18 transformer groupings showing how many spare transformers need to be purchased to meet the spare transformer inventory requirements. Out of these 18, one group requires three spares, one group requires two spares, and 16 groups require one spare. The total number of spares within these groups add up to 21 spare transformers excluding the transformers that will be purchased to replace the failed Apponaug substation transformer and the spare transformer for Block Island substation which is classified as a transmission asset.

The middle paragraph in the response to DIV-2-17 (corrected), page 1 does describe 21 groups requiring one spare transformer, two groups requiring two spares, and two groups requiring three. This does add up to 31 spares. This paragraph should have stated that there are 20 groups requiring one spare transformer, three groups requiring two spares, and two groups requiring three. This adds up to 32 spare transformers.

PUC 6-9

Request:

On DIV 2-17 (corrected), page 3, it appears from the table that there are 20 groups requiring one transformer, three groups requiring 2 spares, and two groups requiring 3 spares. Please confirm this adds up to 32 spares.

Response:

The table shown in DIV 2-17 (corrected), page 3, does indicate that there are 20 groups that require one spare transformer, three groups that require two spare transformers, and two groups that require three spare transformers. This adds up to the 32 required spare transformers.

PUC 6-10

Request:

Please explain the difference between the number of spare transformers table in DIV 2-2 (corrected) and the table DIV 2-17 (corrected). Please recreate the table from DIV 2-17, adding a column for how many spares are proposed for each line. Please add an additional column showing in which year the Company proposes to make the purchase and another additional column showing in which year the Company expects to take delivery.

Response:

The table shown in response to DIV 2-2 (corrected) reflects the number of spare transformers that the Company must purchase (per transformer grouping) to meet the spare transformer inventory requirement. This does not include spare transformers that already are in inventory.

The table shown in response to DIV 2-17 (corrected) reflects the total number of spares needed in inventory for each transformer grouping.

Please see Attachment PUC 6-10 which shows the table from the response to DIV 2-17, with columns for how many spares are proposed for each line, when the Company proposes to make the purchase, and when the Company expects to take delivery.

The Company will review each transformer grouping annually and make updated recommendations on the spare transformers that the Company plans to purchase during the upcoming fiscal year. The Company will base its decisions on asset health, updated contingency analysis, and projects that impact the transformer grouping numbers.

		N	Number Of Spares					Spare Transformer Purchase					Spare Tranformer Delivery				
Voltage and Rating	Winding Configuration	# OF UNITS IN SERVICE	0	1	2	3	# of Proposed Spares	FY25	FY26	FY27	FY28	FY29	FY27	FY28	FY29	FY30	FY31
115-13.2kV 33/44/55 LTC	Delta-Wye	20	0.7408	0.9631	0.9964	0.9997	2	1			1		1			1	
115-13.2 24/32/40 LTC	Delta-Wye	34	0.6005	0.9067	0.9848	0.9981	3		1	1		1		1	1		1
115-34.5kV 48/64/80	Delta-Wye	1	0.9851	0.9999	1.0000	1.0000	1		1					1			
115-34.5kV 33/44/55	Wye-Wye	7	0.9003	0.9949	0.9998	1.0000	1					1					1
115-34.5kV 33/44/55	Delta-Wye	1	0.9851	0.9999	1.0000	1.0000	1					1					1
115Y/66.4kV - 34.5Y/19.92kV 33/44/55 MVA with LTC	Wye-Wye-Delta	3	0.9560	0.9990	1.0000	1.0000	1					1					1
115-34.5-13.8 24/32/40 MVA	Wye-Wye	2	0.9704	0.9996	1.0000	1.0000	1				1					1	
115-23kV 30/40/50	Delta-ZigZag	2	0.9704	0.9996	1.0000	1.0000	1			1					1		
115-23kV 30/40/50	Wye-Wye	6	0.9139	0.9962	0.9999	1.0000	0										
115-23-13.2kV 40/53/66	Wye-Wye-Delta	3	0.9560	0.9990	1.0000	1.0000	0										
115Y/66.4kV - 24kV 33/44/55 LTC	Wye-Delta	2	0.9704	0.9996	1.0000	1.0000	1		1					1			
115-11.5kV 33/44/55MVA LTC	Wye-Wye	6	0.9139	0.9962	0.9999	1.0000	0										
69-13.8kV 24/32/40 LTC	Delta-Wye	1	0.9851	0.9999	1.0000	1.0000	1	1					1				
69-24 kV 25/33.3/46.6 MVA LTC	Wye-Delta	1	0.9851	0.9999	1.0000	1.0000	1				1					1	
33.6-12.470Y kV 24/32/40 MVA LTC	Delta-Wye	5	0.9277	0.9973	0.9999	1.0000	1			1					1		
33.6-12.470Y kV 12/16/20 MVA LTC	Delta-Wye	6	0.9139	0.9962	0.9999	1.0000	0										
34.5x23-12.47 kV 7.5/9.375 MVA	Delta-Wye	27	0.6670	0.9371	0.9918	0.9992	1			1					1		
34.5-12.47kV 7.5/9.375MVA	Delta-ZigZag	1	0.9851	0.9999	1.0000	1.0000	1		1					1			
34.5-11.0 kV 12/16/20 MVA	ZigZag-Delta	3	0.9560	0.9990	1.0000	1.0000	1	1					1				
34.5-4kV 6/7.5MVA LTC	Delta-Delta	1	0.9851	0.9999	1.0000	1.0000	0										
23.5-13.2 kV 15/20/25 MVA LTC	Delta-Wye	4	0.9418	0.9983	1.0000	1.0000	1		1					1			
23-11.5 kV 7.5/9.375 MVA LTC	Delta-Delta	2	0.9704	0.9996	1.0000	1.0000	0										
23-11.5kV 10/12.5MVA	ZigZag-Delta	2	0.9704	0.9996	1.0000	1.0000	1				1					1	
22.9-4.16 kV 7.5/9.375 MVA LTC	Delta-Wye	14	0.8106	0.9808	0.9987	0.9999	1			1					1		
11.5-4.16/2.4Y kV 10.0/12.5 MVA LTC	Delta-Wye	2	0.9704	0.9996	1.0000	1.0000	0										

PUC 6-11

Request:

On DIV 2-3, the second paragraph states, in part, "this realistic lead time extension has increased the required inventory level of spare transformers from 20 to 32." Reconcile the reference to 32 with the DIV 2-2 (corrected) sum (from 6-9).

Response:

For an explanation of how the information in the response to DIV 2-2 (corrected) corresponds to the Company's determination that there is a need for 32 spare transformers, please refer to the Company's responses to PUC 6-8, PUC 6-10, PUC 6-12, and PUC 6-13.

PUC 6-12

Request:

Referencing the response to DIV 2-2 (corrected) please confirm the number of spare transformers in the table adds to 21 and that if you add Apponaug, the Company is proposing to purchase a total of 22 transformers.

Response:

The Company confirms that the number of spare transformers in the table in the Company's response to DIV-2-2 (corrected) adds up to 21. The total number of transformers the Company proposes to purchase is 23, which includes: (i) the 21 spare transformers identified in the Company's response to DIV 2-2 (corrected); (ii) the replacement for the failed Apponaug substation transformer; and (iii) the spare transformer for the Block Island substation, which is classified as a transmission asset.

PUC 6-13

Request:

Referencing Book 1, Bates page 148, the Company indicates there are 7 existing spare transformers in inventory. In DIV 2-3, the Company advises there are 9 existing spare transformers in inventory. How many spare transformers are in inventory today? How many spare transformers have been ordered to date that have not yet been delivered?

Response:

The Company currently has eight (8) distribution class spare transformers in inventory today. Two (2) of the transformers, however, correspond to a transformer grouping that requires only one (1) spare transformer in inventory. Therefore, in relation to the Poisson analysis and when planning for future transformer purposes, these two transformers are counted as one spare transformer.

As explained in greater detail below, the Company currently has enough spare transformers to fulfill seven (7) of the spare transformer inventory requirements, and the Company has identified two (2) additional spare transformers that will soon be available for a total of nine (9) spare transformers it can count on when planning future purchases.

The Company currently has one spare transformer on order to replace the spare transformer that was used at Westerly. The transformer is expected to be delivered during April 2024.

In Book 1, at Bates page 148, the Company said that it has seven (7) existing spare transformers in inventory because, based on the Poisson analysis the Company is using to determine the required number of spare transformers, the Company needs only one spare transformer for the 115-11.5kV grouping, but currently has two spare transformers (which are transmission assets) that fit into that grouping. Accordingly, the Company did not count this additional spare when analyzing its need for additional inventory.

In the Company's response to DIV 2-3, the Company said that it had nine (9) spare transformers because it was identifying the total number of transformers it could rely on for purposes of determining future purchasing needs. That total of nine (9) includes: (i) the seven (7) identified in Book 1, at Bates page 148, (ii) the spare transformer on order to replace the spare transformer that was used at Westerly, and (iii) a spare transformer that will be made available by the retirement of Dyer St. substation.

PUC 6-14

Request:

Referencing the EEI quartile results in DIV 3-16, what is the source of these tables? Which utilities were included in the data? If that is not known, please describe any known information about the survey population.

Response:

The data regarding EEI quartile results in the tables included in the Company's response to DIV 3-16 is based on the 2018 through 2022 EEI Reliability Survey results. Although there are more than 80 utilities included in the EEI Reliability Survey, based on EEI policy, the participating companies remain anonymous. The Company does not have additional information about the survey population.

PUC 6-15

Request:

Referencing Bates page 158 (DARP), the Company states, "This is a reliability-focused strategy designed to meet both state regulatory targets and support RI Energy's goal of national and regional first quartile reliability performance?" Please define what the Company means by national and regional first quartile (i.e., JD Power, EEI Survey, IEEE, other).

Response:

The Company considers national and regional first quartile reliability performance to be:

- Achieving first quartile performance in SAIFI and SAIDI for the IEEE Distribution Working Group PES Distribution Reliability Benchmarking, National (medium sized utility) and Regional (northeast) categories.

- Achieving first quartile performance for Customers Experiencing Multiple Interruptions (CEMI) for the Edison Electric Institute (EEI) Survey.

- Achieving first quartile performance for J.D. Power Electric Utility Residential Customer Satisfaction Study, focusing on Power Quality and Reliability.

PUC 6-16

Request:

Referencing Attachment DIV 7-7-1, Reliability Details tab, specifically the before and after SAIFI, SAIDI, and CAIDI references, it appears the Company has assumed a 25% improvement through ERR. What is the basis of this assumption?

Response:

The assumption for a 25% reliability improvement for the ERR program was based on discussions with subject matter experts within the Company. The results of the ERR analysis can vary greatly per feeder. The draft results of recently completed ERR analyses are as follows:

- 155F2 - 46% reduction
- 155F4 - 24% reduction
- 155F6 - 8% reduction
- 36W44 - 23% reduction
- 21F1 - 64% reduction

As can be seen from this subset, a 25% reliability improvement is reasonable.

For purposes of this response, the Company re-ran the ERR Docket 4600 analysis with a 5% reliability improvement and found the benefit-cost ratio to be 1.70. The breakeven point (benefits ~ costs) is at a reliability improvement of approximately 3.2%. Although the 25% assumption is reasonable, the Company notes that the program is cost effective at a much lower reliability improvement.

PUC 6-17

Request:

Referencing the table in Book 1, Bates pages 169 through 171 (in the CEMI-4 Attachment), please explain how the Company chose the ERR projects highlighted in green. Could all of the line items in the table qualify as ERR? Please explain. Is there a different prioritization weighting for ERR from that which was provided in Figure 5 on Bates page 163? Please explain.

Response:

The Company selected the ERR circuits per Section 4 of the ERR Guidance Document, Bates page 190. Specifically, the Company finds the 5% worst performing feeders, approximately 20. Then the list is refined based on consultation with Field Operations and the Control Center. Any circuits that have been in the ERR or the CEMI programs in the last three years will be excluded as improvements would have recently been proposed, in progress, or completed.

All the line items in the table in Book 1, Bates pages 169 through 171 could qualify for the ERR program subject to the guidance above.

PUC 6-18

Request:

Referencing the response to PUC 3-28, g. and h., please explain how the "first two projects identified as CEMI-4" would have directly impacted the number of outages the customer that experienced 10 interruptions between April 2022 and April 2023. In other words, if they had been installed before April 2022, which outages that that customer experienced would have been avoided and how? (The answer should include a listing of the cause of each of the 10 outages).

Response:

The first two projects in PUC 3-28, part f, are listed below. The combined cost of both projects is approximately $28,000.

Title/Description	Storms WO	Status
Replace 3-65K fuses with 3-65K CMRs at P44 Arcadia Road, Hopkinton.	30792008	Complete July 2023
Install a40K CMR on Phase B (RH) and a 40K fuse on Phase C (LH) at P7 Arcadia Road. Review P1 Arcadia Road to confirm there is no C/O. Hopkinton	30828751	Complete October 2023

The 65 amp cutout mounted reclosers installed at pole 44 Arcadia Road add a reclosing feature to a three phase lateral line that extends through a heavily treed area for 1 mile and serves 201 customers.

The two single phase cutout mounted reclosers installed at pole 7 Arcadia Road serve two line taps. The (LH) left tap serves the customer experiencing CEMI 10.

Of the ten interruptions the customer experienced in 2021, three events would most likely have been avoided. All ten events are listed in the table below.

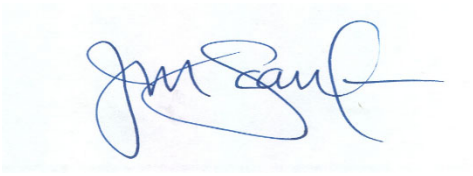
PUC 6-18, page 2

56-155F8 Customer with 10 interruptions from January 01 through December 2021.					
Event	**date**	**Address**	**Cause**	**Potentially Avoided outages**	**Reasoning**
8371040	2/2/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree - Broken Limb	No	Permeant interruption
8377551	3/2/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree Fell	No	Fault was upstream of work location
8378344	3/3/2021	XX BITGOOD RD, HOPE VALLEY, RI	Insulation failure	Yes	Insulator flash overs are typically temporary. CMR would have avoiding the outage
8387999	6/7/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree Fell	No	Fault was upstream of work location
8392942	7/8/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree - Broken Limb	Yes	Tree limb interruptions are typically temporary. CMR would have avoiding the outage
8405050	8/22/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree Fell	No	Fault was upstream of work location
8405065	8/22/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree - Broken Limb	Yes	Tree limb interruptions are typically temporary. CMR would have avoiding the outage
8401413	8/24/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree Fell	No	Permeant interruption
8402373	9/2/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree Fell	No	Permeant interruption
8456887	11/12/2021	XX BITGOOD RD, HOPE VALLEY, RI	Tree Fell	No	Fault was upstream work location

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was 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.



Joanne M. Scanlon

February 20, 2024
Date

Docket No. 23-48-EL – RI Energy's Electric ISR Plan FY 2025
Service List as of 1/25/2024

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