nationalgrid

Andrew S. Marcaccio
Senior Counsel

February 5, 2021

VIA ELECTRONIC MAIL

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

RE: Docket 5098 - Proposed FY 2022 Electric Infrastructure, Safety, and Reliability Plan
Responses to PUC Data Requests – Set 1

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed[1], please find the Company's responses to the Public Utilities Commission's First 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 5098 Service List
John Bell, Division
Greg Booth, Division
Tiffany Parenteau, Esq.
Al Contente, Division

[1] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by an original and five hard copies filed with the Clerk within 24 hours of the electronic filing.

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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 5, 2021
Date

Docket No. 5098 - National Grid's Electric ISR Plan FY 2022
Service List as of 1/28//2021

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File an original & five (5) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.harrington@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107
Matthew Sullivan, Green Development	ms@green-ri.com;	

PUC 1-1

Request:

Please update all relevant schedules using the forecast approved by the Commission in Docket 5076 and extrapolating rate class consumption from the forecast for purposes of the allocations. (NOTE: Use the Docket 5076 forecast to extrapolate April through December 2021, and the Company's most recent forecast available for the months of January through March of 2022).

Response:

Please see Attachment PUC 1-1A for the illustrative Operation & Maintenance Factors and illustrative CapEx Factors (Section 6) calculated based in part on the forecast approved by the Commission in Docket No. 5076 and in part on the most recent forecast for the months of January 2022 through March 2022, derived on page 5. Please see Attachment PUC 1-1B for the illustrative Bill Impacts (Section 7) based on the illustrative factors presented in Attachment PUC 1-1A.

Prepared by or under the supervision of: Shira Horowitz and Dan Gallagher

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors Calculations - Summary
Summary of Illustrative Factors
(for the 12 months beginning April 1, 2021)

		Residential A-16 / A-60 (a)	Small C&I C-06 (b)	General C&I G-02 (c)	Large Demand B-32 (d)	Large Demand G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	O&M Factor per kWh	$0.00208	$0.00212	$0.00180	$0.00090	$0.00090	$0.01193	$0.00040
(2)	O&M Factor per kW	n/a	n/a	n/a	$0.05	n/a	n/a	n/a
(3)	CapEx kWh Charge	$0.00555	$0.00482	n/a	n/a	n/a	$0.00724	$0.00056
(4)	CapEx kW Charge	n/a	n/a	$1.46	$1.42	$1.42	n/a	n/a
(5)	Back-Up Service CapEx kW Charge	n/a	n/a	n/a	$0.14	n/a	n/a	n/a

(1) Page 2, Line (6); Column (d) applicable to supplemental kWh deliveries only
(2) Page 4, Column (a), Line (4), applicable to backup service only
(3) Page 3, Line (6)
(4) Columns (c), (d), and (e) per Page 3, Line (8); Column (d) applicable to supplemental service only
(5) Page 4, Column (a), Line (6), applicable to backup service only

The Narragansett Electric Company
FY22 Illustrative Operations & Maintenance Factors
(for the 12 months beginning April 1, 2021)

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B-32 / G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	FY2022 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$11,983,000						
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$44,205	$22,620	$4,919	$7,563	$7,045	$2,036	$22
(3)	Percentage of Total	100.00%	51.17%	11.13%	17.11%	15.94%	4.61%	0.05%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$11,983,000	$6,131,783	$1,333,432	$2,050,162	$1,909,744	$551,915	$5,964
(5)	Forecasted kWh - April 2021 through March 2022	6,867,308,226	2,943,700,985	627,551,230	1,134,253,593	2,100,784,386	46,262,213	14,755,819
(6)	Illustrative Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00208	$0.00212	$0.00180	$0.00090	$0.01193	$0.00040

(1) per Section 5: Attachment 1, page 1, line (4) column (b)
(2) per RIPUC 4770, Compliance Attachment 6, (Schedule 1B), page 3, line 88
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per page 5
(6) Line (4) ÷ Line (5), truncated to 5 decimal places

The Narragansett Electric Company
FY22 Illustrative CapEx Factors
(for the 12 months beginning April 1, 2021)

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B-32 / G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	FY2022 Capital Investment Component of Revenue Requirement	$29,460,447						
(2)	Total Rate Base ($000s)	$729,511	$404,995	$75,009	$117,155	$123,849	$8,296	$208
(3)	Percentage of Total	100.00%	55.52%	10.28%	16.06%	16.98%	1.14%	0.03%
(4)	Allocated Revenue Requirement	$29,460,447	$16,355,236	$3,029,140	$4,731,175	$5,001,500	$335,008	$8,388
(5)	Forecasted kWh - April 2021 through March 2022	6,867,308,226	2,943,700,985	627,551,230	1,134,253,593	2,100,784,386	46,262,213	14,755,819
(6)	Illustrative CapEx Factor - kWh charge		$0.00555	$0.00482	n/a	n/a	$0.00724	$0.00056
(7)	Forecasted kW - April 2021 through March 2022				3,232,304	3,520,479		
(8)	Illustrative CapEx Factor - kW Charge		n/a	n/a	$1.46	$1.42	n/a	n/a

(1) per Section 5: Attachment 1, page 1, Line (13), Column (b)
(2) RIPUC 4770, Compliance Attachment 6, (Schedule 1A), page 1, Line 9
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per page 5
(6) For non demand-based rate classes, Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) For demand-based rate classes, Line (4) ÷ Line (7), truncated to 2 decimal places
Note: charges apply to kW>10 for rate class G-02 and kW>200 for rate class B-32/G-32

The Narragansett Electric Company
Calculation of Illustrative Operations & Maintenance and CapEx Factors
and Illustrative Base Distribution Charge for Back-up Service Rates

		Large Demand B-32 (a)
	Operations & Maintenance Factors	
(1)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$1,909,744
(2)	Forecasted kW - April 2021 through March 2022	3,520,479
(3)	Illustrative Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW	$0.54
(4)	Illustrative Discounted O&M kW Factor Charge effective 4/1/2021	$0.05
	CapEx Factors	
(5)	Illustrative CapEx kW Factor Charge effective 4/01/2021	$1.42
(6)	Illustrative Discounted CapEx kW Factor Charge effective 4/1/2021	$0.14

(1) Page 2, Line (4), Column (e)
(2) per Company forecasts
(3) Line (1) ÷ Line (2), truncated to 2 decimal places
(4) Line (3) x .10, truncated to two decimal places
(5) Page 3, Line (8), Column (e)
(6) Line (5) x .10, truncated to two decimal places

Calculation of kWh Forecast for the period April 2021 - March 2022 per Information Request PUC 1-1

	Total	Residential A-16 / A60	Small C&I C-06	General C&I G-02	Large Demand B-32 / G-32	Lighting S-05 / S-06 S-10 / S-14	Propulsion X-01	Notes
2020 Weather Normalized - Actual								
1/1/2020	568,153,547	294,503,834	62,580,228	116,141,935	86,255,825	6,467,545	2,204,180	
2/1/2020	608,314,427	239,877,544	54,795,149	99,925,982	207,276,081	4,225,916	2,213,755	
3/1/2020	596,182,219	234,417,233	56,442,758	99,058,389	200,590,710	3,298,573	2,374,556	
4/1/2020	566,279,899	224,759,655	50,819,647	90,531,717	193,635,087	5,146,676	1,387,116	
5/1/2020	523,745,152	209,086,246	47,613,776	80,779,496	183,082,082	2,711,088	472,466	
6/1/2020	543,600,694	222,946,156	48,286,602	86,434,827	182,778,030	2,682,390	472,688	
7/1/2020	687,500,203	329,106,458	58,167,216	105,139,117	191,982,569	2,212,848	891,994	
8/1/2020	738,887,313	369,235,889	61,435,667	116,096,933	189,095,711	2,215,519	807,594	
9/1/2020	636,699,275	286,133,641	56,297,014	103,401,558	187,668,198	2,337,826	861,038	
10/1/2020	561,004,393	222,885,124	53,837,022	98,676,784	180,398,013	4,079,858	1,127,593	
11/1/2020	520,863,739	217,514,831	45,748,107	85,382,181	167,208,778	3,825,460	1,184,382	
12/1/2020	556,078,854	240,794,676	50,252,253	92,546,116	165,735,480	5,233,279	1,517,051	
	7,107,309,714	3,091,261,287	646,275,437	1,174,115,035	2,135,706,565	44,436,979	15,514,411	
2021 Forecast								
1/1/2021	593,178,691	267,500,628	52,450,547	96,335,553	170,210,664	5,093,995	1,587,304	
2/1/2021	544,253,804	239,026,221	48,658,231	89,606,853	160,457,986	5,035,604	1,468,909	
3/1/2021	529,725,921	225,117,967	48,405,341	89,458,375	161,221,034	4,060,332	1,462,873	
4/1/2021	520,730,962	210,993,726	49,309,548	91,212,558	164,063,089	3,659,304	1,492,738	
5/1/2021	449,411,420	163,900,079	44,806,614	83,393,214	153,013,069	2,944,251	1,354,192	
6/1/2021	510,346,489	199,885,913	49,223,919	91,336,892	165,471,791	2,937,374	1,490,600	
7/1/2021	650,338,728	288,254,246	58,184,513	107,513,431	191,655,004	2,966,058	1,765,475	
8/1/2021	672,095,210	303,512,973	59,272,755	109,398,000	194,713,591	3,400,435	1,797,455	
9/1/2021	616,035,712	265,069,954	56,228,765	103,764,958	185,203,990	4,064,898	1,703,147	
10/1/2021	495,113,634	181,758,425	49,642,376	91,874,650	165,959,410	4,377,607	1,501,165	
11/1/2021	478,187,794	178,203,642	47,386,219	87,602,946	158,591,994	4,972,866	1,430,127	
12/1/2021	547,127,026	228,418,321	51,013,836	93,901,449	167,124,575	5,125,846	1,542,999	
	6,606,545,391	2,751,642,095	614,582,666	1,135,398,879	2,037,686,198	48,638,569	18,596,984	
Average								
1/1/2021	580,666,119	281,002,231	57,515,388	106,238,744	128,233,244	5,780,770	1,895,742	Average from Docket 5076
2/1/2021	576,284,115	239,451,882	51,726,690	94,766,418	183,867,034	4,630,760	1,841,332	Average from Docket 5076
3/1/2021	562,954,070	229,767,600	52,424,049	94,258,382	180,905,872	3,679,452	1,918,714	Average from Docket 5076
4/1/2021	543,505,431	217,876,690	50,064,598	90,872,137	178,849,088	4,402,990	1,439,927	Average from Docket 5076
5/1/2021	486,578,286	186,493,163	46,210,195	82,086,355	168,047,575	2,827,669	913,329	Average from Docket 5076
6/1/2021	526,973,591	211,416,035	48,755,260	88,885,860	174,124,911	2,809,882	981,644	Average from Docket 5076
7/1/2021	668,919,465	308,680,352	58,175,864	106,326,274	191,818,787	2,589,453	1,328,735	Average from Docket 5076
8/1/2021	705,491,261	336,374,431	60,354,211	112,747,467	191,904,651	2,807,977	1,302,525	Average from Docket 5076
9/1/2021	626,367,493	275,601,797	56,262,890	103,583,258	186,436,094	3,201,362	1,282,092	Average from Docket 5076
10/1/2021	528,059,014	202,321,774	51,739,699	95,275,717	173,178,712	4,228,733	1,314,379	Average from Docket 5076
11/1/2021	499,525,766	197,859,237	46,567,163	86,492,563	162,900,386	4,399,163	1,307,255	Average from Docket 5076
12/1/2021	551,602,940	234,606,499	50,633,044	93,223,783	166,430,027	5,179,562	1,530,025	Average from Docket 5076
1/1/2022	601,588,691	272,390,151	54,872,294	94,732,363	173,475,805	4,957,245	1,160,832	Per Revised 2021 Forecast
2/1/2022	568,211,573	254,230,878	51,957,757	89,873,915	166,149,324	4,902,762	1,096,937	Per Revised 2021 Forecast
3/1/2022	560,484,714	245,849,978	51,958,254	90,153,901	167,469,026	3,955,413	1,098,141	Per Revised 2021 Forecast
Calendar Year 2020	6,856,927,553	2,921,451,691	630,429,051	1,154,756,957	2,086,696,381	46,537,774	17,055,697	Matches forecast used for Energy Efficiency Charge Calculation in Docket 5076
April 2021 - March 2022	6,867,308,226	2,943,700,985	627,551,230	1,134,253,593	2,100,784,386	46,262,213	14,755,819	

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Illustrative
Rates Applicable to A-16 Rate Customers

Monthly kWh	Rates Effective October 1, 2020				Illustrative Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage of Customers
	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	
(a)	(b)	(c)	(d)	(e) = (a) + (b) + (c)	(f)	(g)	(h)	(i) = (f) + (g) + (h)	(j) = (f) - (b)	(k) = (g) - (c)	(l) = (h) - (d)	(m) = (j) + (k) + (l)	(n) = (j) / (e)	(o) = (g) / (e)	(p) = (h) / (e)	(q) = (m) / (e)	(r)
150	$25.79	$15.56	$1.72	$43.07	$26.03	$15.56	$1.73	$43.32	$0.24	$0.00	$0.01	$0.25	0.6%	0.0%	0.0%	0.6%	30.1%
300	$42.63	$31.11	$3.07	$76.81	$43.09	$31.11	$3.09	$77.29	$0.46	$0.00	$0.02	$0.48	0.6%	0.0%	0.0%	0.6%	12.9%
400	$53.85	$41.48	$3.97	$99.30	$54.47	$41.48	$4.00	$99.95	$0.62	$0.00	$0.03	$0.65	0.6%	0.0%	0.0%	0.7%	11.6%
500	$65.07	$51.85	$4.87	$121.79	$65.85	$51.85	$4.90	$122.60	$0.78	$0.00	$0.03	$0.81	0.6%	0.0%	0.0%	0.7%	9.6%
600	$76.29	$62.22	$5.77	$144.28	$77.22	$62.22	$5.81	$145.25	$0.93	$0.00	$0.04	$0.97	0.6%	0.0%	0.0%	0.7%	7.7%
700	$87.51	$72.59	$6.67	$166.77	$88.60	$72.59	$6.72	$167.91	$1.09	$0.00	$0.05	$1.14	0.7%	0.0%	0.0%	0.7%	19.0%
1,200	$143.62	$124.44	$11.17	$279.23	$145.48	$124.44	$11.25	$281.17	$1.86	$0.00	$0.08	$1.94	0.7%	0.0%	0.0%	0.7%	6.8%
2,000	$233.40	$207.40	$18.37	$459.17	$236.50	$207.40	$18.50	$462.40	$3.10	$0.00	$0.13	$3.23	0.7%	0.0%	0.0%	0.7%	2.3%

			Rates Effective October 1, 2020 (s)	Illustrative Rates (t)	Line Item on Bill
(1)	Distribution Customer Charge		$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge		$0.80	$0.80	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge		$2.16	$2.16	RE Growth Program
(4)	Distribution Charge (per kWh)		$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge		$0.00212	$0.00208	
(6)	Operating & Maintenance Expense Reconciliation Factor		$0.00002	$0.00002	
(7)	CapEx Factor Charge		$0.00396	$0.00555	
(8)	CapEx Reconciliation Factor		$0.00090	$0.00090	
(9)	Revenue Decoupling Adjustment Factor		$0.00118	$0.00118	
(10)	Pension Adjustment Factor		($0.00073)	($0.00073)	
(11)	Storm Fund Replenishment Factor		$0.00288	$0.00288	
(12)	Arrearage Management Adjustment Factor		$0.00015	$0.00015	
(13)	Performance Incentive Factor		$0.00005	$0.00005	
(14)	Low Income Discount Recovery Factor		$0.00176	$0.00176	
(15)	Long-term Contracting for Renewable Energy Charge		$0.00931	$0.00931	Renewable Energy Distribution Charge
(16)	Net Metering Charge		$0.00266	$0.00266	
(17)	Base Transmission Charge		$0.03096	$0.03096	Transmission Charge
(18)	Transmission Adjustment Factor		($0.00189)	($0.00189)	
(19)	Transmission Uncollectible Factor		$0.00038	$0.00038	
(20)	Base Transition Charge		($0.00074)	($0.00074)	Transition Charge
(21)	Transition Adjustment		($0.00008)	($0.00008)	
(22)	Energy Efficiency Program Charge		$0.01353	$0.01353	Energy Efficiency Programs
(23)	Standard Offer Service Base Charge		$0.09568	$0.09568	Supply Services Energy Charge
(24)	SOS Adjustment Factor		($0.00294)	($0.00294)	
(25)	SOS Adminstrative Cost Adjustment Factor		$0.00230	$0.00230	
(26)	Renewable Energy Standard Charge		$0.00866	$0.00866	
	Line Item on Bill				
(27)	Customer Charge		$6.00	$6.00	
(28)	LIHEAP Enhancement Charge		$0.80	$0.80	
(29)	RE Growth Program		$2.16	$2.16	
(30)	Transmission Charge	kWh x	$0.02945	$0.02945	
(31)	Distribution Energy Charge	kWh x	$0.05809	$0.05964	
(32)	Transition Charge	kWh x	($0.00082)	($0.00082)	
(33)	Energy Efficiency Programs	kWh x	$0.01353	$0.01353	
(34)	Renewable Energy Distribution Charge	kWh x	$0.01197	$0.01197	
(35)	Supply Services Energy Charge	kWh x	$0.10370	$0.10370	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (t): Line (5) per Attachment PUC 1-1A, Page 1, Line (1), Column (a). Line (7) per Attachment PUC 1-1A, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Illustrative
Rates Applicable to A-60 Rate Customers

Monthly kWh	Rates Effective October 1, 2020: Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Illustrative Rates: Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	$ Increase (Decrease): Delivery Services	Supply Services	GET	Total	Increase (Decrease) % of Total Bill: Delivery Services	Supply Services	GET	Total	Percentage of Customers
(a)	(b)	(c)	(d) = [(b)+(c)] x-.25	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.25	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) ÷ [(b)+(d)]	(s) = (o) ÷ (c)	(t) = (p) ÷ (f)	(u) = (q) ÷ (g)	(v)
150	$25.53	$15.56	($10.27)	$30.82	$1.28	$32.10	$25.76	$15.56	($10.33)	$30.99	$1.29	$32.28	$0.17	$0.00	$0.01	$0.18	0.5%	0.0%	0.0%	0.6%	32.1%
300	$42.10	$31.11	($18.30)	$54.91	$2.29	$57.20	$42.56	$31.11	($18.42)	$55.25	$2.30	$57.55	$0.34	$0.00	$0.01	$0.35	0.6%	0.0%	0.0%	0.6%	15.4%
400	$53.14	$41.48	($23.66)	$70.96	$2.96	$73.92	$53.76	$41.48	($23.81)	$71.43	$2.98	$74.41	$0.47	$0.00	$0.02	$0.49	0.6%	0.0%	0.0%	0.7%	12.5%
500	$64.19	$51.85	($29.01)	$87.03	$3.63	$90.66	$64.97	$51.85	($29.21)	$87.61	$3.65	$91.26	$0.58	$0.00	$0.02	$0.60	0.6%	0.0%	0.0%	0.7%	9.6%
600	$75.24	$62.22	($34.37)	$103.09	$4.30	$107.39	$76.17	$62.22	($34.60)	$103.79	$4.32	$108.11	$0.70	$0.00	$0.02	$0.72	0.7%	0.0%	0.0%	0.7%	7.2%
700	$86.28	$72.59	($39.72)	$119.15	$4.96	$124.11	$87.37	$72.59	($39.99)	$119.97	$5.00	$124.97	$0.82	$0.00	$0.04	$0.86	0.7%	0.0%	0.0%	0.7%	16.4%
1,200	$141.51	$124.44	($66.49)	$199.46	$8.31	$207.77	$143.37	$124.44	($66.95)	$200.86	$8.37	$209.23	$1.40	$0.00	$0.06	$1.46	0.7%	0.0%	0.0%	0.7%	5.2%
2,000	$229.88	$207.40	($109.32)	$327.96	$13.67	$341.63	$232.98	$207.40	($110.10)	$330.28	$13.76	$344.04	$2.32	$0.00	$0.09	$2.41	0.7%	0.0%	0.0%	0.7%	1.6%

	Rates Effective October 1, 2020 (w)	Illustrative Rates (x)	Line Item on Bill
(1) Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$2.16	$2.16	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04580	$0.04580	
(5) Operating & Maintenance Expense Charge	$0.00212	$0.00208	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(7) CapEx Factor Charge	$0.00396	$0.00555	
(8) CapEx Reconciliation Factor	$0.00090	$0.00090	
(9) Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	Distribution Energy Charge
(10) Pension Adjustment Factor	($0.00073)	($0.00073)	
(11) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12) Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(13) Performance Incentive Factor	$0.00005	$0.00005	
(14) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15) Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(16) Net Metering Charge	$0.00266	$0.00266	
(17) Base Transmission Charge	$0.03096	$0.03096	
(18) Transmission Adjustment Factor	($0.00189)	($0.00189)	Transmission Charge
(19) Transmission Uncollectible Factor	$0.00038	$0.00038	
(20) Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(21) Transition Adjustment	($0.00008)	($0.00008)	
(22) Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(23) Standard Offer Service Base Charge	$0.09568	$0.09568	
(24) SOS Adjustment Factor	($0.00294)	($0.00294)	Supply Services Energy Charge
(25) SOS Adminstrative Cost Adjustment Factor	$0.00230	$0.00230	
(26) Renewable Energy Standard Charge	$0.00866	$0.00866	
Line Item on Bill			
(27) Customer Charge	$6.00	$6.00	
(28) LIHEAP Enhancement Charge	$0.80	$0.80	
(29) RE Growth Program	$2.16	$2.16	
(30) Transmission Charge	$0.02945	$0.02945	
(31) Distribution Energy Charge	$0.05633	$0.05788	
(32) Transition Charge	($0.00082)	($0.00082)	
(33) Energy Efficiency Programs	$0.01353	$0.01353	
(34) Renewable Energy Distribution Charge	$0.01197	$0.01197	
(35) Supply Services Energy Charge	$0.10370	$0.10370	
(36) Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

Column (x): Line (5) per Attachment PUC 1-1A, Page 1, Line (1), Column (a). Line (7) per Attachment PUC 1-1A, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Illustrative
Rates Applicable to A-60 Rate Customers

Monthly kWh	Rates Effective October 1, 2020 Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Illustrative Rates Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	$ Increase (Decrease) Delivery Services	Supply Services	GET	Total	Increase (Decrease) % of Total Bill Delivery Services	Supply Services	GET	Total	Percentage of Customers
			(d) = [(b)+(c)] x-.30	(e) = (b) + (c) + (d)		(g) = (e) + (f)			(j) = [(h)+(i)] x-.30	(k) = (h) + (i) + (j)		(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) ÷ [(b)+(d)]	(s) = (o) ÷ (c)	(t) = (p) ÷ (f)	(u) = (q) ÷ (g)	
(a)	(b)	(c)			(f)		(h)	(i)			(l)										(v)
150	$25.53	$15.56	($12.33)	$28.76	$1.20	$29.96	$25.76	$15.56	($12.40)	$28.92	$1.21	$30.13	$0.16	$0.00	$0.01	$0.17	0.5%	0.0%	0.0%	0.6%	32.1%
300	$42.10	$31.11	($21.96)	$51.25	$2.14	$53.39	$42.56	$31.11	($22.10)	$51.57	$2.15	$53.72	$0.32	$0.00	$0.01	$0.33	0.6%	0.0%	0.0%	0.6%	15.4%
400	$53.14	$41.48	($28.39)	$66.23	$2.76	$68.99	$53.76	$41.48	($28.57)	$66.67	$2.78	$69.45	$0.44	$0.00	$0.02	$0.46	0.6%	0.0%	0.0%	0.7%	12.5%
500	$64.19	$51.85	($34.81)	$81.23	$3.38	$84.61	$64.97	$51.85	($35.05)	$81.77	$3.41	$85.18	$0.54	$0.00	$0.03	$0.57	0.6%	0.0%	0.0%	0.7%	9.6%
600	$75.24	$62.22	($41.24)	$96.22	$4.01	$100.23	$76.17	$62.22	($41.52)	$96.87	$4.04	$100.91	$0.65	$0.00	$0.03	$0.68	0.6%	0.0%	0.0%	0.7%	7.2%
700	$86.28	$72.59	($47.66)	$111.21	$4.63	$115.84	$87.37	$72.59	($47.99)	$111.97	$4.67	$116.64	$0.76	$0.00	$0.04	$0.80	0.7%	0.0%	0.0%	0.7%	16.4%
1,200	$141.51	$124.44	($79.79)	$186.16	$7.76	$193.92	$143.37	$124.44	($80.34)	$187.47	$7.81	$195.28	$1.31	$0.00	$0.05	$1.36	0.7%	0.0%	0.0%	0.7%	5.2%
2,000	$229.88	$207.40	($131.18)	$306.10	$12.75	$318.85	$232.98	$207.40	($132.11)	$308.27	$12.84	$321.11	$2.17	$0.00	$0.09	$2.26	0.7%	0.0%	0.0%	0.7%	1.6%

		Rates Effective October 1, 2020 (w)	Illustrative Rates (x)	Line Item on Bill
(1)	Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$2.16	$2.16	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	
(5)	Operating & Maintenance Expense Charge	$0.00212	$\boxed{\$0.00208}$	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(7)	CapEx Factor Charge	$0.00396	$\boxed{\$0.00555}$	
(8)	CapEx Reconciliation Factor	$0.00090	$0.00090	
(9)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	Distribution Energy Charge
(10)	Pension Adjustment Factor	($0.00073)	($0.00073)	
(11)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12)	Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(13)	Performance Incentive Factor	$0.00005	$0.00005	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00266	$0.00266	
(17)	Base Transmission Charge	$0.03096	$0.03096	
(18)	Transmission Adjustment Factor	($0.00189)	($0.00189)	Transmission Charge
(19)	Transmission Uncollectible Factor	$0.00038	$0.00038	
(20)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(21)	Transition Adjustment	($0.00008)	($0.00008)	
(22)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(23)	Standard Offer Service Base Charge	$0.09568	$0.09568	
(24)	SOS Adjustment Factor	($0.00294)	($0.00294)	Supply Services Energy Charge
(25)	SOS Adminstrative Cost Adjustment Factor	$0.00230	$0.00230	
(26)	Renewable Energy Standard Charge	$0.00866	$0.00866	
	Line Item on Bill			
(27)	Customer Charge	$6.00	$6.00	
(28)	LIHEAP Enhancement Charge	$0.80	$0.80	
(29)	RE Growth Program	$2.16	$2.16	
(30)	Transmission Charge	$0.02945	$0.02945	
(31)	Distribution Energy Charge	$0.05633	$\boxed{\$0.05788}$	
(32)	Transition Charge	($0.00082)	($0.00082)	
(33)	Energy Efficiency Programs	$0.01353	$0.01353	
(34)	Renewable Energy Distribution Charge	$0.01197	$0.01197	
(35)	Supply Services Energy Charge	$0.10370	$0.10370	
(36)	Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

Column (x): Line (5) per Attachment PUC 1-1A, Page 1, Line (1), Column (a). Line (7) per Attachment PUC 1-1A, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Illustrative
Rates Applicable to C-06 Rate Customers

	Rates Effective October 1, 2020				Illustrative Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	of Customers
(a)	(b)	(c)	(d)	(e)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
250	$41.13	$23.34	$2.69	$67.16	$41.49	$23.34	$2.70	$67.53	$0.36	$0.00	$0.01	$0.37	0.5%	0.0%	0.0%	0.6%	56.3%
500	$68.11	$46.67	$4.78	$119.56	$68.82	$46.67	$4.81	$120.30	$0.71	$0.00	$0.03	$0.74	0.6%	0.0%	0.0%	0.6%	16.9%
1,000	$122.06	$93.34	$8.98	$224.38	$123.49	$93.34	$9.03	$225.86	$1.43	$0.00	$0.05	$1.48	0.6%	0.0%	0.0%	0.7%	8.1%
1,500	$176.02	$140.01	$13.17	$329.20	$178.16	$140.01	$13.26	$331.43	$2.14	$0.00	$0.09	$2.23	0.7%	0.0%	0.0%	0.7%	5.0%
2,000	$229.97	$186.68	$17.36	$434.01	$232.83	$186.68	$17.48	$436.99	$2.86	$0.00	$0.12	$2.98	0.7%	0.0%	0.0%	0.7%	13.6%

		Rates Effective October 1, 2020	Illustrative Rates	Line Item on Bill
		(o)	(p)	
(1)	Distribution Customer Charge	$10.00	$10.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$3.35	$3.35	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04482	$0.04482	
(5)	Operating & Maintenance Expense Charge	$0.00212	$0.00212	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(7)	CapEx Factor Charge	$0.00339	$0.00482	
(8)	CapEx Reconciliation Factor	$0.00085	$0.00085	
(9)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	Distribution Energy Charge
(10)	Pension Adjustment Factor	($0.00073)	($0.00073)	
(11)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12)	Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(13)	Performance Incentive Factor	$0.00005	$0.00005	
(14)	Low Income Discount Recovery Factor	$0.00176	$0.00176	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00266	$0.00266	
(17)	Base Transmission Charge	$0.03110	$0.03110	
(18)	Transmission Adjustment Factor	($0.00467)	($0.00467)	Transmission Charge
(19)	Transmission Uncollectible Factor	$0.00031	$0.00031	
(20)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(21)	Transition Adjustment	($0.00008)	($0.00008)	
(22)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(23)	Standard Offer Service Base Charge	$0.08150	$0.08150	
(24)	SOS Adjustment Factor	$0.00094	$0.00094	Supply Services Energy Charge
(25)	SOS Adminstrative Cost Adjustment Factor	$0.00224	$0.00224	
(26)	Renewable Energy Standard Charge	$0.00866	$0.00866	

	Line Item on Bill		
(27)	Customer Charge	$10.00	$10.00
(28)	LIHEAP Enhancement Charge	$0.80	$0.80
(29)	RE Growth Program	$3.35	$3.35
(30)	Transmission Charge	$0.02674	$0.02674
(31)	Distribution Energy Charge	$0.05649	$0.05792
(32)	Transition Charge	($0.00082)	($0.00082)
(33)	Energy Efficiency Programs	$0.01353	$0.01353
(34)	Renewable Energy Distribution Charge	$0.01197	$0.01197
(35)	Supply Services Energy Charge	$0.09334	$0.09334

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (p): Line (5) per Attachment PUC 1-1A, Page 1, Line (1), Column (b). Line (7) per Attachment PUC 1-1A, Page 1, Line (3), Column (b). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Illustrative
Rates Applicable to G-02 Rate Customers

			Rates Effective October 1, 2020				Illustrative Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i)	Delivery Services (j)	Supply Services (k)	GET (l)	Total (m)
20	200	4,000	$526.47	$373.36	$37.49	$937.32	$531.81	$373.36	$37.72	$942.89	$5.34	$0.00	$0.23	$5.57	0.6%	0.0%	0.0%	0.6%
50	200	10,000	$1,166.85	$933.40	$87.51	$2,187.76	$1,187.55	$933.40	$88.37	$2,209.32	$20.70	$0.00	$0.86	$21.56	0.9%	0.0%	0.0%	1.0%
100	200	20,000	$2,234.15	$1,866.80	$170.87	$4,271.82	$2,280.45	$1,866.80	$172.80	$4,320.05	$46.30	$0.00	$1.93	$48.23	1.1%	0.0%	0.0%	1.1%
150	200	30,000	$3,301.45	$2,800.20	$254.24	$6,355.89	$3,373.35	$2,800.20	$257.23	$6,430.78	$71.90	$0.00	$2.99	$74.89	1.1%	0.0%	0.0%	1.2%
20	300	6,000	$617.53	$560.04	$49.07	$1,226.64	$623.09	$560.04	$49.30	$1,232.43	$5.56	$0.00	$0.23	$5.79	0.5%	0.0%	0.0%	0.5%
50	300	15,000	$1,394.50	$1,400.10	$116.44	$2,911.04	$1,415.75	$1,400.10	$117.33	$2,933.18	$21.25	$0.00	$0.89	$22.14	0.7%	0.0%	0.0%	0.8%
100	300	30,000	$2,689.45	$2,800.20	$228.74	$5,718.39	$2,736.85	$2,800.20	$230.71	$5,767.76	$47.40	$0.00	$1.97	$49.37	0.8%	0.0%	0.0%	0.9%
150	300	45,000	$3,984.40	$4,200.30	$341.03	$8,525.73	$4,057.95	$4,200.30	$344.09	$8,602.34	$73.55	$0.00	$3.06	$76.61	0.9%	0.0%	0.0%	0.9%
20	400	8,000	$708.59	$746.72	$60.64	$1,515.95	$714.37	$746.72	$60.88	$1,521.97	$5.78	$0.00	$0.24	$6.02	0.4%	0.0%	0.0%	0.4%
50	400	20,000	$1,622.15	$1,866.80	$145.37	$3,634.32	$1,643.95	$1,866.80	$146.28	$3,657.03	$21.80	$0.00	$0.91	$22.71	0.6%	0.0%	0.0%	0.6%
100	400	40,000	$3,144.75	$3,733.60	$286.60	$7,164.95	$3,193.25	$3,733.60	$288.62	$7,215.47	$48.50	$0.00	$2.02	$50.52	0.7%	0.0%	0.0%	0.7%
150	400	60,000	$4,667.35	$5,600.40	$427.82	$10,695.57	$4,742.55	$5,600.40	$430.96	$10,773.91	$75.20	$0.00	$3.14	$78.34	0.7%	0.0%	0.0%	0.7%
20	500	10,000	$799.65	$933.40	$72.21	$1,805.26	$805.65	$933.40	$72.46	$1,811.51	$6.00	$0.00	$0.25	$6.25	0.3%	0.0%	0.0%	0.3%
50	500	25,000	$1,849.80	$2,333.50	$174.30	$4,357.60	$1,872.15	$2,333.50	$175.24	$4,380.89	$22.35	$0.00	$0.94	$23.29	0.5%	0.0%	0.0%	0.5%
100	500	50,000	$3,600.05	$4,667.00	$344.46	$8,611.51	$3,649.65	$4,667.00	$346.53	$8,663.18	$49.60	$0.00	$2.07	$51.67	0.6%	0.0%	0.0%	0.6%
150	500	75,000	$5,350.30	$7,000.50	$514.62	$12,865.42	$5,427.15	$7,000.50	$517.82	$12,945.47	$76.85	$0.00	$3.20	$80.05	0.6%	0.0%	0.0%	0.6%
20	600	12,000	$890.71	$1,120.08	$83.78	$2,094.57	$896.93	$1,120.08	$84.04	$2,101.05	$6.22	$0.00	$0.26	$6.48	0.3%	0.0%	0.0%	0.3%
50	600	30,000	$2,077.45	$2,800.20	$203.24	$5,080.89	$2,100.35	$2,800.20	$204.19	$5,104.74	$22.90	$0.00	$0.95	$23.85	0.5%	0.0%	0.0%	0.5%
100	600	60,000	$4,055.35	$5,600.40	$402.32	$10,058.07	$4,106.05	$5,600.40	$404.44	$10,110.89	$50.70	$0.00	$2.12	$52.82	0.5%	0.0%	0.0%	0.5%
150	600	90,000	$6,033.25	$8,400.60	$601.41	$15,035.26	$6,111.75	$8,400.60	$604.68	$15,117.03	$78.50	$0.00	$3.27	$81.77	0.5%	0.0%	0.0%	0.5%

	Rates Effective October 1, 2020 (o)	Illustrative Rates (p)	Line Item on Bill
(1) Distribution Customer Charge	$145.00	$145.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$32.45	$32.45	RE Growth Program
(4) Base Distribution Demand Charge (per kW > 10kW)	$6.90	$6.90	Distribution Demand Charge
(5) CapEx Factor Demand Charge (per kW > 10kW)	$0.97	$1.46	
(6) Distribution Charge (per kWh)	$0.00476	$0.00476	Distribution Energy Charge
(7) Operating & Maintenance Expense Charge	$0.00169	$0.00180	
(8) Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(9) CapEx Reconciliation Factor	$0.00064	$0.00064	
(10) Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	
(11) Pension Adjustment Factor	($0.00073)	($0.00073)	
(12) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13) Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(14) Performance Incentive Factor	$0.00005	$0.00005	
(15) Low Income Discount Recovery Factor	$0.00176	$0.00176	
(16) Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(17) Net Metering Charge	$0.00266	$0.00266	
(18) Transmission Demand Charge	$4.37	$4.37	Transmission Demand Charge
(19) Base Transmission Charge	$0.01214	$0.01214	Transmission Adjustment
(20) Transmission Adjustment Factor	($0.00399)	($0.00399)	
(21) Transmission Uncollectible Factor	$0.00030	$0.00030	
(22) Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(23) Transition Adjustment	($0.00008)	($0.00008)	
(24) Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(25) Standard Offer Service Base Charge	$0.08150	$0.08150	Supply Services Energy Charge
(26) SOS Adjustment Factor	$0.00094	$0.00094	
(27) SOS Adminstrative Cost Adjustment Factor	$0.00224	$0.00224	
(28) Renewable Energy Standard Charge	$0.00866	$0.00866	
Line Item on Bill			
(29) Customer Charge	$145.00	$145.00	
(31) LIHEAP Enhancement Charge	$0.80	$0.80	
(30) RE Growth Program	$32.45	$32.45	
(32) Transmission Adjustment	$0.00845	$0.00845	
(33) Distribution Energy Charge	$0.01240	$0.01251	
(34) Distribution Demand Charge	$7.87	$8.36	
(35) Transmission Demand Charge	$4.37	$4.37	
(34) Transition Charge	($0.00082)	($0.00082)	
(35) Energy Efficiency Programs	$0.01353	$0.01353	
(36) Renewable Energy Distribution Charge	$0.01197	$0.01197	
(37) Supply Services Energy Charge	$0.09334	$0.09334	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (p): Line (5) per Attachment PUC 1-1A, Page 1, Line (4), Column (c). Line (7) per Attachment PUC 1-1A, Page 1, Line (1), Column (c). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Illustrative
Rates Applicable to G-32 Rate Customers

			Rates Effective October 1, 2020				Illustrative Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i)	Delivery Services (j)	Supply Services (k)	GET (l)	Total (m)
200	200	40,000	$4,172.35	$2,951.60	$296.83	$7,420.78	$4,173.95	$2,951.60	$296.90	$7,422.45	$1.60	$0.00	$0.07	$1.67	0.0%	0.0%	0.0%	0.0%
750	200	150,000	$15,316.45	$11,068.50	$1,099.37	$27,484.32	$15,586.45	$11,068.50	$1,110.62	$27,765.57	$270.00	$0.00	$11.25	$281.25	1.0%	0.0%	0.0%	1.0%
1,000	200	200,000	$20,381.95	$14,758.00	$1,464.16	$36,604.11	$20,773.95	$14,758.00	$1,480.50	$37,012.45	$392.00	$0.00	$16.34	$408.34	1.1%	0.0%	0.0%	1.1%
1,500	200	300,000	$30,512.95	$22,137.00	$2,193.75	$54,843.70	$31,148.95	$22,137.00	$2,220.25	$55,506.20	$636.00	$0.00	$26.50	$662.50	1.2%	0.0%	0.0%	1.2%
2,500	200	500,000	$50,774.95	$36,895.00	$3,652.91	$91,322.86	$51,898.95	$36,895.00	$3,699.75	$92,493.70	$1,124.00	$0.00	$46.84	$1,170.84	1.2%	0.0%	0.1%	1.3%
5,000	200	1,000,000	$101,429.95	$73,790.00	$7,300.83	$182,520.78	$103,773.95	$73,790.00	$7,398.50	$184,962.45	$2,344.00	$0.00	$97.67	$2,441.67	1.3%	0.0%	0.1%	1.3%
7,500	200	1,500,000	$152,084.95	$110,685.00	$10,948.75	$273,718.70	$155,648.95	$110,685.00	$11,097.25	$277,431.20	$3,564.00	$0.00	$148.50	$3,712.50	1.3%	0.0%	0.1%	1.4%
10,000	200	2,000,000	$202,739.95	$147,580.00	$14,596.67	$364,916.62	$207,523.95	$147,580.00	$14,796.00	$369,899.95	$4,784.00	$0.00	$199.33	$4,983.33	1.3%	0.0%	0.1%	1.4%
20,000	200	4,000,000	$405,359.95	$295,160.00	$29,188.33	$729,708.28	$415,023.95	$295,160.00	$29,591.00	$739,774.95	$9,664.00	$0.00	$402.67	$10,066.67	1.3%	0.0%	0.1%	1.4%
200	300	60,000	$5,127.55	$4,427.40	$398.12	$9,953.07	$5,129.95	$4,427.40	$398.22	$9,955.57	$2.40	$0.00	$0.10	$2.50	0.0%	0.0%	0.0%	0.0%
750	300	225,000	$18,898.45	$16,602.75	$1,479.22	$36,980.42	$19,171.45	$16,602.75	$1,490.59	$37,264.79	$273.00	$0.00	$11.37	$284.37	0.7%	0.0%	0.0%	0.8%
1,000	300	300,000	$25,157.95	$22,137.00	$1,970.62	$49,265.57	$25,553.95	$22,137.00	$1,987.12	$49,678.07	$396.00	$0.00	$16.50	$412.50	0.8%	0.0%	0.0%	0.8%
1,500	300	450,000	$37,676.95	$33,205.50	$2,953.44	$73,835.89	$38,318.95	$33,205.50	$2,980.19	$74,504.64	$642.00	$0.00	$26.75	$668.75	0.9%	0.0%	0.0%	0.9%
2,500	300	750,000	$62,714.95	$55,342.50	$4,919.06	$122,976.51	$63,848.95	$55,342.50	$4,966.31	$124,157.76	$1,134.00	$0.00	$47.25	$1,181.25	0.9%	0.0%	0.0%	1.0%
5,000	300	1,500,000	$125,309.95	$110,685.00	$9,833.12	$245,828.07	$127,673.95	$110,685.00	$9,931.62	$248,290.57	$2,364.00	$0.00	$98.50	$2,462.50	1.0%	0.0%	0.0%	1.0%
7,500	300	2,250,000	$187,904.95	$166,027.50	$14,747.19	$368,679.64	$191,498.95	$166,027.50	$14,896.94	$372,423.39	$3,594.00	$0.00	$149.75	$3,743.75	1.0%	0.0%	0.0%	1.0%
10,000	300	3,000,000	$250,499.95	$221,370.00	$19,661.25	$491,531.20	$255,323.95	$221,370.00	$19,862.25	$496,556.20	$4,824.00	$0.00	$201.00	$5,025.00	1.0%	0.0%	0.0%	1.0%
20,000	300	6,000,000	$500,879.95	$442,740.00	$39,317.50	$982,937.45	$510,623.95	$442,740.00	$39,723.50	$993,087.45	$9,744.00	$0.00	$406.00	$10,150.00	1.0%	0.0%	0.0%	1.0%
200	400	80,000	$6,082.75	$5,903.20	$499.41	$12,485.36	$6,085.95	$5,903.20	$499.55	$12,488.70	$3.20	$0.00	$0.14	$3.34	0.0%	0.0%	0.0%	0.0%
750	400	300,000	$22,480.45	$22,137.00	$1,859.06	$46,476.51	$22,756.45	$22,137.00	$1,870.56	$46,764.01	$276.00	$0.00	$11.50	$287.50	0.6%	0.0%	0.0%	0.6%
1,000	400	400,000	$29,933.95	$29,516.00	$2,477.08	$61,927.03	$30,333.95	$29,516.00	$2,493.75	$62,343.70	$400.00	$0.00	$16.67	$416.67	0.6%	0.0%	0.0%	0.7%
1,500	400	600,000	$44,840.95	$44,274.00	$3,713.12	$92,828.07	$45,488.95	$44,274.00	$3,740.12	$93,503.07	$648.00	$0.00	$27.00	$675.00	0.7%	0.0%	0.0%	0.7%
2,500	400	1,000,000	$74,654.95	$73,790.00	$6,185.21	$154,630.16	$75,798.95	$73,790.00	$6,232.87	$155,821.82	$1,144.00	$0.00	$47.66	$1,191.66	0.7%	0.0%	0.0%	0.8%
5,000	400	2,000,000	$149,189.95	$147,580.00	$12,365.42	$309,135.37	$151,573.95	$147,580.00	$12,464.75	$311,618.70	$2,384.00	$0.00	$99.33	$2,483.33	0.8%	0.0%	0.0%	0.8%
7,500	400	3,000,000	$223,724.95	$221,370.00	$18,545.62	$463,640.57	$227,348.95	$221,370.00	$18,696.62	$467,415.57	$3,624.00	$0.00	$151.00	$3,775.00	0.8%	0.0%	0.0%	0.8%
10,000	400	4,000,000	$298,259.95	$295,160.00	$24,725.83	$618,145.78	$303,123.95	$295,160.00	$24,928.50	$623,212.45	$4,864.00	$0.00	$202.67	$5,066.67	0.8%	0.0%	0.0%	0.8%
20,000	400	8,000,000	$596,399.95	$590,320.00	$49,446.67	$1,236,166.62	$606,223.95	$590,320.00	$49,856.00	$1,246,399.95	$9,824.00	$0.00	$409.33	$10,233.33	0.8%	0.0%	0.0%	0.8%
200	500	100,000	$7,037.95	$7,379.00	$600.71	$15,017.66	$7,041.95	$7,379.00	$600.87	$15,021.82	$4.00	$0.00	$0.16	$4.16	0.0%	0.0%	0.0%	0.0%
750	500	375,000	$26,062.45	$27,671.25	$2,238.90	$55,972.60	$26,341.45	$27,671.25	$2,250.53	$56,263.23	$279.00	$0.00	$11.63	$290.63	0.5%	0.0%	0.0%	0.5%
1,000	500	500,000	$34,709.95	$36,895.00	$2,983.54	$74,588.49	$35,113.95	$36,895.00	$3,000.37	$75,009.32	$404.00	$0.00	$16.83	$420.83	0.5%	0.0%	0.0%	0.6%
1,500	500	750,000	$52,004.95	$55,342.50	$4,472.81	$111,820.26	$52,658.95	$55,342.50	$4,500.06	$112,501.51	$654.00	$0.00	$27.25	$681.25	0.6%	0.0%	0.0%	0.6%
2,500	500	1,250,000	$86,594.95	$92,237.50	$7,451.35	$186,283.80	$87,748.95	$92,237.50	$7,499.44	$187,485.89	$1,154.00	$0.00	$48.09	$1,202.09	0.6%	0.0%	0.0%	0.6%
5,000	500	2,500,000	$173,069.95	$184,475.00	$14,897.71	$372,442.66	$175,473.95	$184,475.00	$14,997.87	$374,946.82	$2,404.00	$0.00	$100.16	$2,504.16	0.6%	0.0%	0.0%	0.7%
7,500	500	3,750,000	$259,544.95	$276,712.50	$22,344.06	$558,601.51	$263,198.95	$276,712.50	$22,496.31	$562,407.76	$3,654.00	$0.00	$152.25	$3,806.25	0.7%	0.0%	0.0%	0.7%
10,000	500	5,000,000	$346,019.95	$368,950.00	$29,790.42	$744,760.37	$350,923.95	$368,950.00	$29,994.75	$749,868.70	$4,904.00	$0.00	$204.33	$5,108.33	0.7%	0.0%	0.0%	0.7%
20,000	500	10,000,000	$691,919.95	$737,900.00	$59,575.84	$1,489,395.79	$701,823.95	$737,900.00	$59,988.50	$1,499,712.45	$9,904.00	$0.00	$412.66	$10,316.66	0.7%	0.0%	0.0%	0.7%
200	600	120,000	$7,993.15	$8,854.80	$702.00	$17,549.95	$7,997.95	$8,854.80	$702.20	$17,554.95	$4.80	$0.00	$0.20	$5.00	0.0%	0.0%	0.0%	0.0%
750	600	450,000	$29,644.45	$33,205.50	$2,618.75	$65,468.70	$29,926.45	$33,205.50	$2,630.50	$65,762.45	$282.00	$0.00	$11.75	$293.75	0.4%	0.0%	0.0%	0.4%
1,000	600	600,000	$39,485.95	$44,274.00	$3,490.00	$87,249.95	$39,893.95	$44,274.00	$3,507.00	$87,674.95	$408.00	$0.00	$17.00	$425.00	0.5%	0.0%	0.0%	0.5%
1,500	600	900,000	$59,168.95	$66,411.00	$5,232.50	$130,812.45	$59,828.95	$66,411.00	$5,260.00	$131,499.95	$660.00	$0.00	$27.50	$687.50	0.5%	0.0%	0.0%	0.5%
2,500	600	1,500,000	$98,534.95	$110,685.00	$8,717.50	$217,937.45	$99,698.95	$110,685.00	$8,766.00	$219,149.95	$1,164.00	$0.00	$48.50	$1,212.50	0.5%	0.0%	0.0%	0.6%
5,000	600	3,000,000	$196,949.95	$221,370.00	$17,430.00	$435,749.95	$199,373.95	$221,370.00	$17,531.00	$438,274.95	$2,424.00	$0.00	$101.00	$2,525.00	0.6%	0.0%	0.0%	0.6%
7,500	600	4,500,000	$295,364.95	$332,055.00	$26,142.50	$653,562.45	$299,048.95	$332,055.00	$26,296.00	$657,399.95	$3,684.00	$0.00	$153.50	$3,837.50	0.6%	0.0%	0.0%	0.6%
10,000	600	6,000,000	$393,779.95	$442,740.00	$34,855.00	$871,374.95	$398,723.95	$442,740.00	$35,061.00	$876,524.95	$4,944.00	$0.00	$206.00	$5,150.00	0.6%	0.0%	0.0%	0.6%
20,000	600	12,000,000	$787,439.95	$885,480.00	$69,705.00	$1,742,624.95	$797,423.95	$885,480.00	$70,121.00	$1,753,024.95	$9,984.00	$0.00	$416.00	$10,400.00	0.6%	0.0%	0.0%	0.6%

		Rates Effective October 1, 2020 (o)	Illustrative Rates (p)	Line Item on Bill
(1)	Distribution Customer Charge	$1,100.00	$1,100.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$267.15	$267.15	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 200kW)	$5.30	$5.30	Distribution Demand Charge
(5)	CapEx Factor Demand Charge (per kW > 200kW)	$0.94	$\boxed{\$1.42}$	
(6)	Distribution Charge (per kWh)	$0.00430	$0.00430	
(7)	Operating & Maintenance Expense Charge	$0.00086	$\boxed{\$0.00090}$	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(9)	CapEx Reconciliation Factor	$0.00033	$0.00033	
(10)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	Distribution Energy Charge
(11)	Pension Adjustment Factor	($0.00073)	($0.00073)	
(12)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13)	Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(14)	Performance Incentive Factor	$0.00005	$0.00005	
(15)	Low Income Discount Recovery Factor	$0.00176	$0.00176	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.00266	$0.00266	
(18)	Transmission Demand Charge	$4.47	$4.47	Transmission Demand Charge
(19)	Base Transmission Charge	$0.01264	$0.01264	
(20)	Transmission Adjustment Factor	($0.00070)	($0.00070)	Transmission Adjustment
(21)	Transmission Uncollectible Factor	$0.00034	$0.00034	
(22)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(23)	Transition Adjustment	($0.00008)	($0.00008)	
(24)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(25)	Standard Offer Service Base Charge	$0.05946	$0.05946	
(26)	SOS Adjustment Factor	$0.00381	$0.00381	Supply Services Energy Charge
(27)	SOS Adminstrative Cost Adjustment Factor	$0.00186	$0.00186	
(28)	Renewable Energy Standard Charge	$0.00866	$0.00866	
	Line Item on Bill			
(29)	Customer Charge	$1,100.00	$1,100.00	
(30)	LIHEAP Enhancement Charge	$0.80	$0.80	
(31)	RE Growth Program	$267.15	$267.15	
(32)	Transmission Adjustment	$0.01228	$0.01228	
(33)	Distribution Energy Charge	$0.01080	$\boxed{\$0.01084}$	
(34)	Distribution Demand Charge	$6.24	$\boxed{\$6.72}$	
(35)	Transmission Demand Charge	$4.47	$4.47	
(34)	Transition Charge	($0.00082)	($0.00082)	
(35)	Energy Efficiency Programs	$0.01353	$0.01353	
(36)	Renewable Energy Distribution Charge	$0.01197	$0.01197	
(37)	Supply Services Energy Charge	$0.07379	$0.07379	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

Column (p): Line (5) per Attachment PUC 1-1A, Page 1, Line (4), Column (e). Line (7) per Attachment PUC 1-1A, Page 1, Line (1), Column (e). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

PUC 1-2

Request:

Please provide a schedule itemizing all the COVID-related costs expected to be incurred in FY2022, comprising the $2 million budget referenced in Section 2 of the capital plan, including a reasonable description of the work giving rise to the cost incurrence. Of the $2 million, please provide an estimate of the revenue requirement impact during FY2022, if any.

Response:

The Company has completed its detailed COVID peak load scenario analysis on all 195 feeders identified during the screening review. All scope being progressed will address either voltage or overload issues created by or exacerbated by COVID load shifts. Many small-scale solutions such as fuse replacements, feeder balancing, and upgrading equipment (load break switches, step down transformers, etc.) to a larger size have been progressed to construction already and the spend has/will occur in FY2021.

COVID related work planned to occur in FY2022 is included in the two tables below. The first table shows the largest scope and highest cost recommendation projects, the 72F3 and 72F5. The Company plans to review these two highest cost recommendations with the Division in a meeting on February 12th prior to progressing them to design and construction. Since the scope is more significant for these feeders, more detailed estimates have been performed. The second table shows smaller scope projects. These smaller scale projects have only been estimated at a high level (totex only). More refined estimates will be developed during detailed design.

Station	Feeder Id	Scope	Capex	Opex	Removal	Total
Lincoln Avenue	**72F5**	Recoductor ~3200 feet of 1/0 and 4/0 AL to 477 AL	$364,000.00	$24,000.00	$111,000.00	$499,000.00
Lincoln Avenue	**72F3**	Reconductor ~2050 feet of 1/0 CU, 2/0CU & 4/0ALto 477 AL	$203,000.00	$14,000.00	$ 62,000.00	$279,000.00
Total			$567,000.00	$38,000.00	$173,000.00	$778,000.00

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Station	Feeder Id	Scope	Estimated cost (totex)
Eldred	45J3	1,600 foot phase extension, 300 foot phase extension, load balancing, & upgrade 3 sets of fuses,	$ 150,000.00
Peacedale	59F3	1600 circuit feet of recondutoring to 477	$ 166,000.00
Phillipsdale	20F2	Reconductor 1290 feet to Al-477 Bare	$ 168,000.00
Wompanaug	48F1	Reconductor 1000 feet to Al-477 Bare	$ 125,000.00
Geneva	71J5	1300 feet of recondutoring to Al-477 Bare	$ 74,000.00
Sprague Street	36J5	600 feet of reconductoring Al-477 Bare	$ 43,000.00
Westerly	16F1	3 regulator replacements	$ 76,000.00
Kenyon	68F2	Transformer/fuse replacements	$ 57,000.00
Clarkson St	13F5	Replace 3 fuses and one airbreak switch	$ 27,239.38
Coventry	54F1	Replace 3 fuses, load balancing, place capacitor back in service	$ 28,195.73
Small scale work*	various	fuse replacements, load balancing, equipment replacement, small scale reconductoring or phase extensions	$ 130,000.00
TOTAL small scale			$ 1,044,435.11
TOTAL 72F3 & 72F5			$ 778,000.00
Overall TOTAL			$ 1,822,435.11

*Small scale recommendations include work on approximately eight feeders. This work has not been estimated at a detailed level since the work is limited. Work in this category includes fuse replacements, load balancing, small scale reconductoring or phase extensions or step down transformer upgrades.

The revenue requirement calculation on any vintage year's ISR capital investment is calculated on the incremental ISR-related rate base, which is incremental to the level of ISR rate base assumed in the Company's last distribution rate case. The level of ISR rate base assumed in current distribution rates was based on a forecast of capital placed into service, set at a level equal to the approved FY 2018 ISR Plan capital in-service as a proxy. Then using that proxy level of plant in service, the Company established the rate years' forecasted levels of plant retirements, cost of removal and NOL/NOL utilization in totality. As the forecasted rate base included in distribution rates was not determined on a per project basis, determining the level of incremental ISR rate base on a per-project basis is nearly impossible. For that reason, the Company is employing a more simplistic approach, using a ratio of the total incremental FY 2022 revenue requirement associated with incremental FY2022 ISR capital investment placed

PUC 1-2, page 3

into service ($6.2 million) over the total budgeted FY2022 capital investment placed into service amount of $114 million, to arrive at the FY2022 revenue requirement impact on a per-project basis, as shown in Column (d) in the chart below.

The FY2022 revenue requirement of $6.2 million includes $3.6 million in depreciation expense, return on investment and associated income taxes on the incremental FY 2022 ISR rate base plus $2.6 million in incremental property tax expense associated with the projected FY 2022 ISR plant in service. Please refer to the calculation of the revenue requirement ratio of 5.44% in the chart below on lines 2-6.

	Project Description	**FY22 Plan Spend**	**Target Placed In-Service FY22 Including COR**	**FY22 Revenue Requirement**
		(b)	(c)	(d) = Line 6 × (c)
1	Covid Scenario Analysis Work RI	$2,000,000	$1,409,364	$76,669

2	FY22 Depreciation, Return and Taxes associated with FY22 investment	$3,644,310
3	FY22 Property tax associated with FY22 investment	$2,566,000
4	Total FY22 revenue requirement associated with FY22 investment	$6,210,310
5	Total FY22 Capital Placed into Service plus Cost of Removal	$114,112,000
6	Ratio of Revenue Requirement to Capital Placed into Service plus Cost of Removal	5.44%

Line notes:

2 Section 5 Attachment 1, Page 18, Line 33, Col (a)
3 Section 5 Attachment 1, Page 27, Line 52, Col (k)
4 Line 2 + Line 3
5 Section 2, Chart 18
6 Line 4 ÷ Line 5

Prepared by or under the supervision of: Caitlin Broderick and Melissa Little

PUC 1-3

Request:

Referring to the Capital Spending Key Driver table on Bates page 94, please provide an explanation and evidentiary support for the FY 2022 budget forecast of an increase of approximately $1 million over FY 2021 in "New Business – Commercial" and over $2 million in "New Business – Residential." In providing the response, please also address why there would be expected increases of this magnitude given the economic impacts caused by the pandemic.

Response:

The specific work performed in the new business category is generally not known more than a year ahead, so the budget is proposed based on actual historical costs, adjusting for any known trends or one-time items.

New Business—Commercial

The Total FY2022 New Business Commercial (NBC) budget of $9.066 million is made up of 3 components:

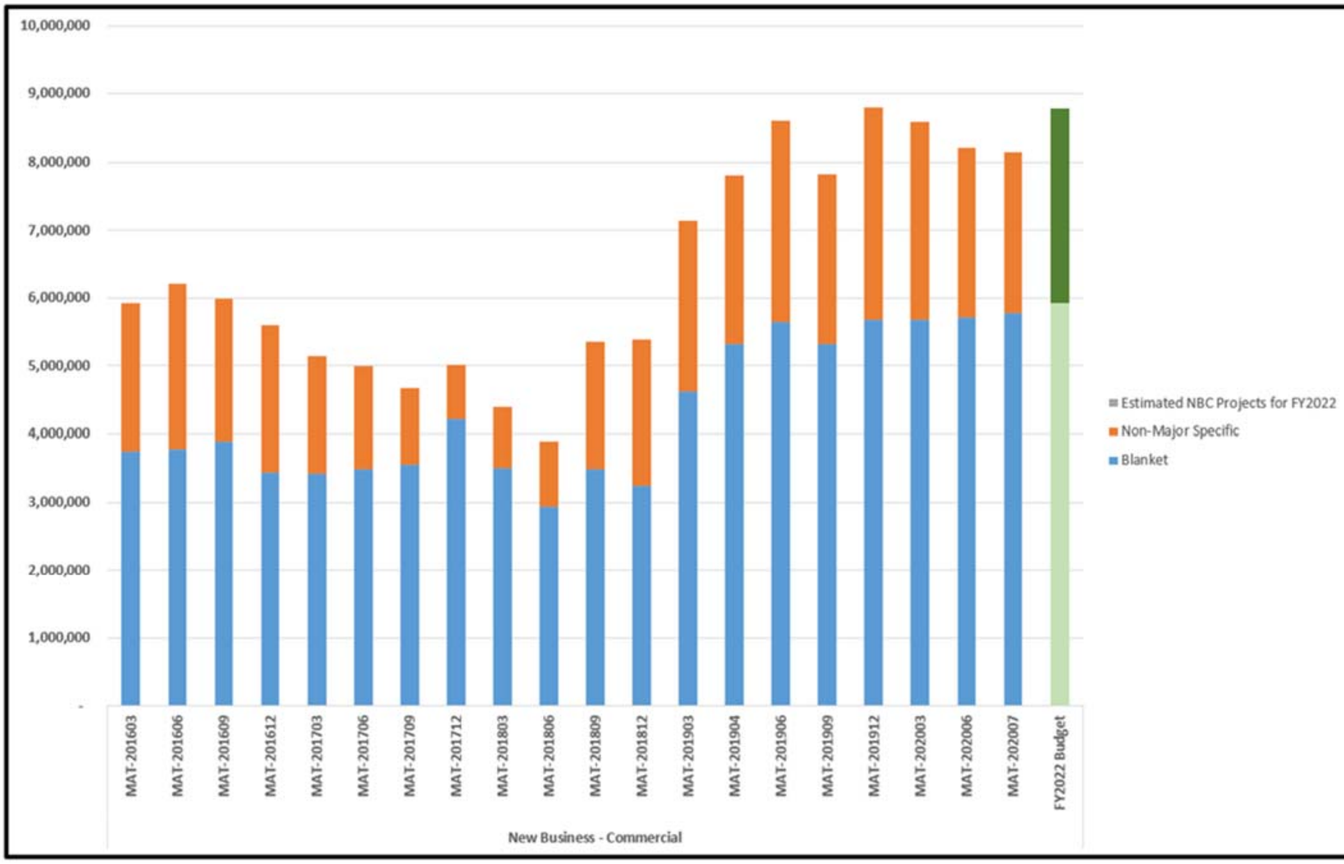
1) Blanket Project ($5.931 million) for small scope work

2) Reserve for NBC Projects that emerge in FY2022 ($2.850 million)

3) Project(s) forecasted to carry over into FY2022 ($0.285 million)

The charts below show the analysis that led to the FY2022 budget estimate for these items. The data used includes New Business Commercial Moving Annual Totals (MAT) from the end of FY20216 through July 2020 (ISR Pre-filing draft submitted to the Division in August 2020). Since developing the budget estimate in FY 2022 in August, the Company noted that the volume of requests for new or upgraded Commercial New Business for the first nine months of the FY 2021 has decreased by 191 (863 vs. 672) from the same period last year. However, due to a great deal of uncertainty about these trends as well as the potentially significant variability in the cost per Commercial requests, the Company used the same method for estimating the upcoming fiscal year budget using the 12-month MAT spending trends, consistent with our practices in prior years. The figures exclude Major Projects as those would be included in the upcoming fiscal year forecast and would not require a reserve. A chart, along with corresponding data is provided below as well an estimate for inflationary cost increases used in our budget estimating process.

PUC 1-3, page 2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MAT-201809
MAT-201812
MAT-201903
MAT-201904
MAT-201906
MAT-201909
MAT-201912
MAT-202003
MAT-202006
MAT-202007
FY2022 Budget
New Business - Commercial
Estimated NBC Projects for FY2022
Non-Major Specific
Blanket

PUC 1-3, page 3

Budget Class	Values	Blanket	Non-Major Specific	Grand Total
New Business - Commercial	MAT-201603	3,749,326	2,182,184	5,931,510
	MAT-201606	3,777,201	2,446,575	6,223,776
	MAT-201609	3,898,062	2,093,411	5,991,473
	MAT-201612	3,445,414	2,151,082	5,596,496
	MAT-201703	3,422,187	1,717,764	5,139,952
	MAT-201706	3,489,511	1,517,243	5,006,754
	MAT-201709	3,555,311	1,115,328	4,670,638
	MAT-201712	4,226,856	790,118	5,016,974
	MAT-201803	3,504,856	887,552	4,392,408
	MAT-201806	2,934,971	964,663	3,899,634
	MAT-201809	3,483,143	1,880,700	5,363,842
	MAT-201812	3,241,900	2,139,014	5,380,914
	MAT-201903	4,630,356	2,516,618	7,146,974
	MAT-201904	5,318,956	2,485,282	7,804,238
	MAT-201906	5,648,111	2,958,449	8,606,560
	MAT-201909	5,319,803	2,505,468	7,825,270
	MAT-201912	5,682,044	3,117,569	8,799,613
	MAT-202003	5,684,599	2,897,850	8,582,449
	MAT-202006	5,717,447	2,491,245	8,208,692
	MAT-202007	5,771,471	2,375,697	8,147,168
	MAT as July	5,771,471	2,375,697	
	Estimate used for FY 2022	5,725,000	2,750,000	

Prepared by or under the supervision of: Patricia C. Easterly

PUC 1-3, page 4

FROM DATA - FY2022 Estimates Used

Blanket Uninflated FY2022 Estimate	5,725,000	
Adjustment for Inflation (1.5%), Economic Increase (1%), Materials (2%) etc.	206,000	3.6%
	5,931,000	

Reserve Uninflated FY2022 Estimate	2,750,000	
Adjustment for Inflation (1.5%), Economic Increase (1%), Materials (2%) etc.	100,000	3.6%
	2,850,000	

New Business—Residential

The Total FY2022 New Business Residential (NBR) budget is made up of 3 components:

1) Blanket Project ($3.720 million), which represents $6.220 million costs less $2.50 million estimated Joint Owned Pole Billing credits)

2) Reserve for NBC Projects that emerge in FY2022 ($0.300 million)

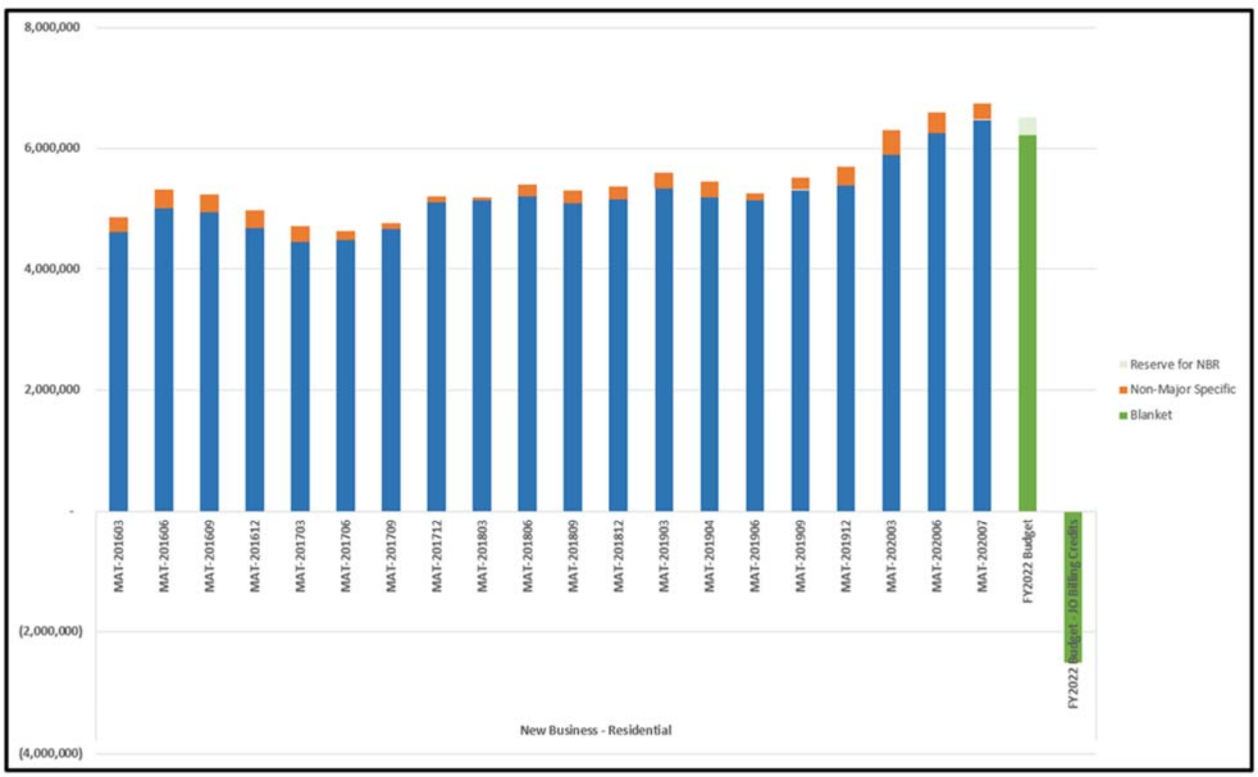
3) Project(s) forecasted to carry over into FY2022 (none)

The charts below show the analysis that led to the FY2022 budget estimate for these items. The data used includes New Business Residential Moving Annual Totals-MAT (excluding the JO Billing work order under this project) from the end of FY20216 through July 2020 (ISR Pre-filing draft submitted to the Division in August 2020). Since developing the July estimate the Company noted the number of requests for new or upgraded Residential New Business service for the first nine months of FY2021 has only slightly decreased by 88 (2,828 vs. 2,740) from the same time period last year. However, due to the uncertainty about these trends the Company utilized the same method for estimating the upcoming fiscal year budget using the 12-month MAT spending trends, as consistent with our practices in prior years.

PUC 1-3, page 5

The figures exclude Major Projects as those would be included in the upcoming fiscal year forecast and would not require a reserve. The estimated Joint Owned Pole Billing is based on FY2022 expected billings based on current agreements. A chart, along with the corresponding data, is provided below as well as an estimate for inflationary cost increases used in our budget estimating processes.

The YTD and forecasted spending in FY 2021 as of December 31, 2020, for new business residential work is $1 million and $2.4 million respectively. However, the New Business Residential Blanket project is where the billing for joint-owned pole installations under the Verizon Joint Owned-Pole agreement is reflected. The billing under this agreement during FY 2021 was $4.1 million and included billing for activity for both FY 2020 and FY 2021 joint-owned pole installations as the Company finalized processes with Verizon for such billing and $1.7 million relates to FY 2020. The FY 2021 forecast excluding the one-time FY 2020 joint-owed pole billing is $4.2 million.



PUC 1-3, page 6

Budget Class	Values	New Business Su Blanket	Non-Major Specific	Grand Total
New Business - Residential	MAT-201603	4,621,826	237,610	4,859,436
	MAT-201606	5,014,566	304,767	5,319,333
	MAT-201609	4,949,563	285,131	5,234,695
	MAT-201612	4,692,555	288,963	4,981,518
	MAT-201703	4,454,897	265,392	4,720,289
	MAT-201706	4,484,661	158,482	4,643,143
	MAT-201709	4,672,426	97,619	4,770,046
	MAT-201712	5,114,168	96,437	5,210,605
	MAT-201803	5,144,584	51,967	5,196,552
	MAT-201806	5,207,722	201,371	5,409,093
	MAT-201809	5,095,517	210,900	5,306,417
	MAT-201812	5,155,083	212,861	5,367,943
	MAT-201903	5,337,762	268,671	5,606,434
	MAT-201904	5,193,813	263,529	5,457,342
	MAT-201906	5,138,040	113,481	5,251,521
	MAT-201909	5,313,984	210,266	5,524,250
	MAT-201912	5,386,723	311,901	5,698,623
	MAT-202003	5,898,181	400,526	6,298,707
	MAT-202006	6,256,936	344,061	6,600,997
	MAT-202007	6,473,390	273,405	6,746,795
	Estimate for FY 2022 Budget	6,070,000	290,000	

FROM DATA - FY2022 Estimates Used

Blanket Uninflated FY2022 Estimate	6,070,000	
Adjustment for Inflation (1.5%), Economic Increase (1%), Materials (2%) etc.	200,000	3.3%
JO POLE BILLING CREDIT ESTIMATE	(2,550,000)	
	3,720,000	

Reserve Uninflated FY2022 Estimate	290,000	
Adjustment for Inflation (1.5%), Economic Increase (1%), Materials (2%) etc.	10,000	3.4%
	300,000	

PUC 1-4

Request:

Referring to the Capital Spending Key Driver table on Bates page 94, please provide an explanation and evidentiary support for the FY 2022 budget forecast of an increase of approximately $9 million over FY 2021in Asset Replacement. Please identify all the Asset Replacement projects that make up the entire $35.4 million in asset replacements, with an explanation why each of the projects are proposed for replacements in FY 2022. Please list the projects in order of priority.

Response:

The Asset Replacement category on Bates page 94 shows an increase of approximately $9 million when comparing the FY 2022 Budget to the FY 2021 Forecast primarily due to the timing of large project spending. In FY 2022, we are proposing $9.7 million for the Dyer Street project and $8.4 million for the projects associated with the Admiral Street substation project. There is also a smaller increase in the Underground Cable program of $1.2 million, which is more than offset by reductions in other projects and programs. In addition, when considering the Asset Condition category overall, the Southeast Substation project, which is reported separately, is expected to be nearly complete in FY 2021 and, therefore, we expect to spend approximately $10.7 million less in FY 2022. Total Asset Condition spending, including the Southeast Substation and I&M, is expected to be $1.6 million less than the FY 2021 Forecast.

Please see Attachment PUC 1-4-1 for a list of projects that make up the entire $35.4 million in asset replacements. For each project listed Attachment PUC 1-4-1 includes the project budget, a summary, and explanations as to why the project is proposed for FY2022, and a priority rank. Please see Attachment PUC 1-4-2 for specific project details for the large Asset Condition projects.

In regard to the priority rankings, the Company respectfully submits that all of the Asset Replacement projects proposed in the FY 2022 ISR plan fall within the same top priority tier and that the Company's decision to include the projects and associated budgets within the plan is an integral component of the Company's statutory responsibility to propose an investment and spending plan for review by the Commission that is reasonably needed to maintain safe and reliable distribution service over the short and long term.

Prepared by or under the supervision of: Caitlin Broderick and David Arthur

Priority	Project	Reason for Proposal	FY21 Forecast $'000s	FY 2022 Budget $'000s	Increase / (Decrease) $'000s
1	Dyer Street Substation	Nearly 100 year old substation with significant asset condition and safety issues.	$2,860	$9,717	$6,857
2	Providence Study (Admiral Street Substation)	Projects resulting from the Providence area study. Addresses significant asset condition issues including indoor substations and underground cable assets. Projects are necessary to maintain reliability for the Providence area and have been carefully planned and synchronized because of the complexity of the Providence area solution and the many years to fully implement the solution.	4,336	8,353	$4,018
3	Battery / Charger Program	Annual program to ensure reliable operation of important assets within Company substations.	195	150	($45)
4	UG Cable Replacement Program	This is an annual program to address chronic asset condition issues on underground cable systems with problematic cable types.	3,774	5,000	$1,226
5	IRURD Projects	This is an annual program to address chronic asset condition issues on Underground Residential Development (URD) systems with problematic cable types in developments where outages have occurred so outages are avoided in the future.	4,852	4,700	($152)
6	Breaker Replacement projects (Franklin Sq, Kent, Pawtucket)	Circuit Breaker Replacement program replaces problematic breaker families that are either obsolete, unsafe or have caused outages in accordance with the breaker replacement program.	1,685	1,829	$144
7	Other smaller projects	This includes vault vent blower replacements, GE type U bushing replacements and Drumrock 14 12.47kV breaker replacements.The vault vent blowers were identified as an additional action item to help mitigate cable deterioration in vaults as part of the Underground Cable repalcement program mentioned above. There are industry known issues with the GE type U bushings so the Company is replacing these proactively to prevent outages due to premature failure. The Drumrock breaker replacement project addresses asset condition issues associated with multiple 12.47kV breakers.	969	1,233	$264
8	Franklin Square 1105 and 1109 lines	This substation work includes rearranging the 1105 and 1109 feeders which is required to move the feeders from Dyer Street to Franklin Square. The project is needed due to the Dyer St elimination project.	2,035	529	($1,506)
9	Asset Replacement Blanket	This is small scale asset condition work to replace damaged assets that are expected to create a failure or safety issue.	4,400	3,592	($808)
	South Street Substation	These costs relate to estimated final payments to contractors for work already done on this in-service project.	224	297	$73
	Hope Substation Pole Replacement and Flood Restoration		368	0	($368)
	Distribution Secondary Network Arc		716		($716)
	Asset Replacement - subtotal		**26,416**	**35,401**	**8,986**
	Inspection & Maintenance Program	This is an annual program whereby distribution line assets undergo a five-yar inspection cycle to replace deteriorated assets to ensure that the distribution and sub-transmission system is safe, reliable, and environmentally sound.	2,900	3,000	$100
	Southeast Substation		12,794	2,082	($10,712)
	Asset Condition - total		**$42,110**	**$40,483**	**($1,627)**

Large Asset Condition projects

The following Asset Condition Project Summary includes the major projects proposed in the Asset Condition spending rationale. At the bottom of each project summary, a statement is included regarding the project's alignment with the developing Long Range Plan.

Projects in Progress

Southeast Sub (New Southeast Substation and Pawtucket No. 1 Indoor Substation)

Distribution Related Project Number(s):	C053657 Southeast Sub (D-Sub) C053658 Southeast Sub (D-Line) C055683 Pawtucket No 1 (D-Sub)
Substation(s) / Feeder(s) Impacted:	Southeast 60W1, 60W2, 60W3, 60W4, 60W5, 60W6, 60W7 Pawtucket No. 1 107W1, 107W2, 107W3, 107W43, 107W49, 107W50, 107W51, 107W53, 107W60, 107W61, 107W65, 107W66, 107W81, 107W84 Pawtucket No. 2 148J1, 148J3, 148J5, 148J7 Valley St 102W51, 102W52
Voltage(s):	13.8 kV and 4.16 kV
Geographic Area Served:	Pawtucket and Central Falls
Summary of Issues:	Pawtucket No. 1 station consists of a four story brick building constructed in 1907 and an outdoor switchyard. It has nineteen 13.8 kV distribution circuits that supply 36,000 customers with 114 MW of load. Three feeders supply a network in downtown Pawtucket with approximately 3MW of load. The brick building was part of a former power plant that was decommissioned in 1975 and is less than 25% utilized. This building houses indoor distribution switchgear and other electrical equipment. The electrical equipment still in service within the building is associated with both the indoor switchgear and the outdoor yard. Some electrical equipment associated with the former power plant has been abandoned in place. The indoor substation has safety risks due to design and equipment condition. Its outmoded design no longer meets currently accepted safety practices and the equipment and protection schemes are becoming unreliable in their function of interrupting faults. The breakers in the indoor substation consist of General Electric H type oil circuit breakers ranging in age from 40 to 93 years old. These breakers are no longer supported by any vendor. A failure on these breakers has resulted in the need for a complete breaker replacement. The indoor substation building has numerous structural issues that are of concern for the continued safe and reliable operation of the substation. A multimillion dollar investment would be anticipated if this building was to remain. A contingency at Pawtucket No.1 involving loss of a transformer or main bus would require significant load to be transferred to adjacent stations utilizing feeder ties. Pawtucket No. 1 only has weak ties to Valley St. station, therefore a significant amount of Pawtucket No. 1 load cannot be picked up during these contingencies.

Recommended Plan	Construct a new eight feeder 115/13.8 kV metal clad station with two transformers and breaker and a half design on a site adjacent to the transmission right of way on York Avenue in the City of Pawtucket. Supply proposed station from the existing 115 kV lines crossing the site, X-3 and T-7. Rearrange the 13.8kV distribution system so that the new station supplies most of the load east of the Seekonk River. Construct a new control house at the Pawtucket No 1 substation site to house the control equipment for the 115 kV station presently located in the indoor substation building. Remove the switchgear in the indoor building and remove all the previously abandoned equipment. Demolish the indoor substation building after all electrical equipment has been removed. At Pawtucket No 1, install 3-phase metering on all feeders supplied from sections 73 and 74 located in the exterior yard which are remaining. Metered quantities shall include amps, volts, MVA and MVAR on all feeders. Total Cost = $38 million (includes all costs with transmission, distribution, operations & maintenance, and removal)
Current Status and Expected In-Service Date	Current Status: - Southeast Sub – Step 4.4b - Construction - Pawtucket No 1 – Step 4.4a - Detail Design Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	Alternative 1: New Metal Clad 115/13.8 kV Station at the Pawtucket No 1 This alternative proposes development of a new 115/13.8 kV metal clad substation, breaker and a half design, in the Pawtucket No. 1 yard. The station will be constructed with two 115/13.8 kV 33/44/55 MVA LTC transformers, eight distribution circuits and two station capacitor banks. After installation of the new switchgear, load at Pawtucket No 1 will be rearranged to allow for the elimination of the 71 bus. There are presently eight circuits on section 71, including three network feeders. The three network circuits are currently dedicated feeders with approximately 3.0 MVA of peak load. It is proposed to supply these network circuits from section 73. The remaining circuits will be resupplied from the new station. Three circuits in section 73 will be resupplied from the new station to free up feeders for the three network circuits. This work will reduce loading on section 73 below the rating of the 2,000 amp bus. The distribution from Pawtucket No 1 is all underground. Therefore, new manhole and ductline infrastructure will be built from the new station out to city streets and intercept the existing underground system when practical. New underground feeder getaways will be installed from the new station and will intercept the existing cables or be routed directly to the riser poles. The existing manhole and ductline infrastructure predominantly consists of 3-inch conduits installed on city streets. Although the age of this infrastructure is unknown, based on the age of the indoor substation it would be reasonable to assume that the majority of this infrastructure dates back to the early 1900's. The diameter on the 3-inch infrastructure is not suitable to house the proposed solid dielectric cables required for the new feeders. New 5 inch diameter infrastructure is required for the new cable. This plan would install a new manhole and duct system to bypass the inadequate 3-inch infrastructure.

	Total Conceptual Cost = $31 million (includes all costs with transmission, distribution, operations & maintenance, and removal). This alternative was estimated to be 33.0% more expensive than the recommended plan at the conceptual engineering phase.
Long Range Plan Alignment	Pawtucket Area Study, dated December 2014. This project is also aligned with National Grid's Strategy for Indoor Substation Rebuild and Refurbishment

Providence Study Phase 1 – Admiral Street Substation

Distribution Related Project Number(s):	C077365 – Clarkson St 13F10 - Hawkins St (D-Line) C077368 – Olneyville 6J5 Feeder Retirement (D-Line) C078734 – Admiral St 4 kV & 11 kV Retirement (D-Line) C078796 – Admiral St 11 kV Rochambeau Supply (D-Line) C078800 – Clarkson St & Lippitt Hill 12 kV Rebuilds (D-Line) C078802 – Olneyville 6J1, 6J3, 6J6, 6J7 Feeder Retirement (D-Line) C078811 – Geneva, Olneyville, Rochambeau 4 kV Retirement (D-Line) C078857 – Harris Ave 4 kV & 11 kV Retirement (D-Line) C078805 – Knightsville 4 kV Retirement (D-Line) C078810 – Harris Ave 1129 and 1137 Retirement (D-Line) C079317 – Harris Ave and Olneyville Supple Line Removal (D-Line) C079318 – Rochambeau Supply Line Removal (D-Line)C078803 – Admiral St 12 kV MH & Duct (D-Line) C078804 – Admiral St 12 kV Cables (D-Line) C078797 – Admiral St Rochambeau Supply (D-Sub) C078735 – Admiral St 115/12.47 kV (D-Sub) C078806 – Knightsville 23/12 kV (D-Sub) C078801 – Admiral St Building Demolition (D-Sub) C078847 – Geneva 4 kV Removal (D-Sub) C078849 – Harris Ave 4 kV & 11 kV Removal (D-Sub) C078850 – Olneyville 4 kV Removal (D-Sub) C078851 – Rochambeau 4 kV Removal (D-Sub) C078951 – Admiral St Switches and Taps (T-Sub)
Substation(s) / Feeder(s) Impacted:	Admiral Street 9J1, 9J2, 9J3, 9J5, 1115, 1117, 1119 Clarkson Street 13F1, 13F2, 13F3, 13F5, 13F6, 13F7, 13F8, 13F9, 13F10 Lippit Hill 79F1, 79F2 Point Street 76F3, 76F4, 76F5 Dyer Street 2J3 Geneva 71J1, 71J2, 71J3, 71J4, 71J5 Olneyville 6J1, 6J2, 6J3, 6J5, 6J6, 6J7, 6J8 Knightsville 66J1, 66J2, 66J3, 66J4, 66J5 Harris Avenue 12J1, 12J2, 12J3, 12J4, 12J5, 12J6, 1129, 1131, 1133, 1137, 1145, 1147 Rochambeau Avenue 37J1, 37J2, 37J3, 37J4, 37J5 Johnston 18F5, 18F7, 18F9
Voltage(s):	12.47 kV, 11.5 kV, 4.16 kV
Geographic Area Served:	City of Providence
Summary of Issues:	Providence is an urban area with a relatively concentrated load. The electrical distribution facilities consist of a mix of older 11 kV and 4.16 kV distribution systems and a newer 12.47 kV distribution system. The distribution circuits are primarily underground in the downtown business district whereas they are overhead in the surrounding residential areas. Much of the underground infrastructure dates back to the period when the system was originally installed in the 1920's. The study identified the main issue to be asset condition. Six of the older stations supplying the area are indoor stations installed between 1924 and 1939 and have a number of asset related concerns. The health and condition of all indoor stations were assessed, and each station assigned a priority score. In addition to the station issues, over 25 miles of underground supply and distribution circuits were identified in the Company's cable replacement program.

	Although asset condition was the main driver, the study also identified some loading, contingency loading, and breaker duty issues.
Recommended Plan	The Providence Study assessed various options to resolve issues identified within the study area and compared the economics of several supply and distribution alternatives. The preferred option recommended the expansion of the 12.47 kV distribution system, conversion of the majority of 11.5 kV and 4.16 kV load to 12.47 kV and elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations. The majority of the new 12.47 kV capacity in the recommended plan would be provided by new 115/12.47 kV stations at Admiral Street, Auburn and South Street. The first phase of alternate analysis was considered in Part A of the Providence Long Term Study. The alternative plans considered in Part A include the items below compared against one for one asset replacement. The purpose of Part B of the Providence Area Study was to create a sequencing of the items recommended in Part A.: • Install a new 23/11 kV transformer at Admiral Street substation to supply Rochambeau Avenue substation. • Convert Admiral Street 11.5 kV and 4.16 kV feeders to 12.47 kV and retire stations. • Demolish the Admiral Street indoor substation and prepare site for new 115/12.47 kV substation. • Build new Admiral Street 115/12.47 kV metal clad substation with four feeders. • Convert the Olneyville 4.16 kV feeders to 12.47 kV and retire the substation. • Install a modular 23/12.47 kV feeder position at Knightsville and convert Knightsville 4.16 kV feeders to 12.47 kV. • Convert Harris Avenue 11.5 kV and 4.16 kV feeders to 12.47 kV and retire substation. • Convert Geneva 4.16 kV feeders to 12.47 kV and retire the substation. • Convert Rochambeau Avenue 4.16 kV feeders to 12.47 kV and retire substation. • Convert Sprague Street and Huntington Park 4.16 kV feeders to 12.47 kV and retire both substations. Total cost is $88 million (includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes)
Current Status and Expected In-Service Date	Current Status – Phase 1A – Step 4.4a Detail Design Phase 1B, 2, 3 and 4 – Step 4.3 Develop & Sanction Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	The alternative analysis for the Admiral Street plan was completed within the Part A study. Part A considered direct one for one replacement of the significant asset issues including complex indoor substation rebuilds and over 25 miles of sub-transmission and distribution cable replacement with an estimated cost over $100 million.
Long Range Plan Alignment	Providence Area Study Implementation Plan 2016 – 2030 (May 2017).

Dyer Street Indoor Substation Replacement

Distribution Related Project Number(s):	C051205 Dyer St replace indoor subst D-SUB C051211 Dyer St replace indoor subst D-LINE
Substation(s) / Feeder(s) Impacted:	Dyer St 2J1, 2J2, 2J3, 2J4,2J5, 2J7, 2J8, 2J9, 2J10, 1102, 1103, 1104, 1106, 1105 NW, 1109 NW Franklin Square 1120, 1142, 1144, 1149
Voltage(s):	11.5 kV, 4.16 kV
Geographic Area Served:	City of Providence
Summary of Issues:	Providence is an urban area with a relatively concentrated load. The electrical distribution facilities consist of a mix of older 11 kV and 4.16 kV distribution systems and a newer 12.47 kV distribution system. The distribution circuits are primarily underground in the downtown business district and the East Side. Much of the underground infrastructure dates back to the period when the system was originally installed in the 1920's. An Asset Condition Study of Dyer St Substation was conducted by Network Asset Planning in 2011, After a review of test records and operating history the study concluded that operation and maintenance of the existing station equipment presented challenges. The main equipment families in this station (breakers, reactors, regulators, switches, relay schemes) are deficient in the areas of performance/maintenance costs when compared to contemporary substation equipment. This station also has design aspects that make it a challenging environment to perform operations and maintenance in. The study identified the main issue to be asset condition. Dyer St is one of six older stations supplying the downtown area reviewed in the Providence Long Term Study (2015). That study recommended the replacement of the 4.16 kV and 11 kV indoor substation. The sequence of planned worked, namely the completion of South St, allows the company to execute the most cost effective plan to eliminate the circa 1925 indoor substation.
Recommended Plan	The preferred option recommends building a new 11.5 kV – 4.16 kV substation within the South St Station outdoor yard. Work at South St will include: • Installing two -11 .5 kV – 4.16 KV transformers, • Installing one 4.16 kV metal clad walk-in switchgear • Installing control panels and protective relay for all elements in the indoor substation's alternate control room. • Building a new duct and manhole system within outdoor yard to accommodate two 11 kV supply lines and eight – 4 kV distribution circuit • Utilizing new and existing duct and manhole system to connect the new 4 kV distribution circuits to the former Dyer St 4 kV circuits. Work at the Dyer St site will include: • Rehabilitation of the historically significant DC / warehouse building as required by the City of Providence. • Removing all retired 4 kV and 11 kV equipment and cable from the Dyer St indoor substation and yard. • Demolition of the Dyer St Indoor Substation building

	The estimated cost for this work is $22 million
Current Status and Expected In-Service Date	Current Status – Step 4.3 - Develop & Sanction Expected In-Service – 4th quarter of FY 2024.
Alternatives:	A new alternative analysis was undertaken as a result of substantial increases in cost for the original plan as well as complexities involved in historical building rehabilitation. The recently completed South St project resulted in an opportunity for an additional alternative not previously possible (recommended alternative above). The original plan is included below as the alternative. The alternative plan involves restoring the currently vacant DC / warehouse building on the southwest corner of National Grid's Dyer St site. Build a new 11 kV to 4.16 kV indoor distribution substation within the restored DC building. Retire the existing circa 1925 Dyer St Indoor Substation at the southeast corner of the site. Remove all 11 kV and 4.16 kV equipment and underground distribution cables associated with the old indoor substation. The estimated cost of this alternative exceeded $30 million.
Long Range Plan Alignment	Providence Area Study Implementation Plan 2016 – 2030 (May 2017).

PUC 1-5

Request:

Referring to the Capital Spending Key Driver table on Bates page 94, labeled "Reliability," the budget for FY 2022 is $8.7 million. The FY 2021 budget was $6.035 million. The current forecast spend for FY 2021 is $3.565.

a. Please provide the rationale for including a budget for FY 2022 that is in excess of the budgeted amount of FY 2021 when the Company does not expect to reach the budget level of spending in FY 2021.
b. Please explain why the budget is more than double most years' actuals dating back to 2011.
c. Please identify all the projects that make up the entire $8.7 million in expenditures, with an explanation why each of the projects are proposed for FY 2022. Please list the projects in order of priority.

Response:

a. In reviewing the data for the response to this question, we noted that we had made a mistake in the classification of System Capacity and Performances projects between Reliability and Load Relief for the FY 2021 forecast and the FY 2022 Budget. Please see a revised summary of that portion of Attachment 1 – Capital Spending by Key Drive Category and Budget Classification table (Bates page 94) as shown below.

	FY 2021 Budget $'000's	FY 2021 Forecast $'000's	FY 2022 Budget $'000's
System Capacity & Performance			
Load Relief	$15,410	$10,912	$8,922
Strategic DER Investments	1,700	0	0
Reliability	6,035	7,696	9,450
Reliability - Feeder Hardening	-	-	-
Total System Capacity & Performance Spending	$23,145	$18,608	$18,372

The Strategic DER Investments are all related to 3V0 and are classified as reliability and therefore should be combined with the reliability budget of $6.035 when comparing to the FY 2021 forecast and FY 2022 budget. The Company forecasts to be close to budget at the end of FY 2021. As shown on Attachment PUC 1-5-1, the FY 2022 budget is $9.450 million, an increase of $1.7 million over the FY 2021 budget and the FY 2021 forecast. The primary drivers of this increase are related to the VVO/CVR program and the New Lafayette project.

Prepared by or under the supervision of: Patricia C. Easterly and Caitlin Broderick

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b. In the earlier years of the ISR plan, the primary programs in the Reliability category were a Feeder Hardening program, some specific project work and Cutout installation and replacement programs. While there are still cutout programs in Reliability in current years, the Feeder Hardening Program is no longer a component of the Reliability category and instead there are targeted program investments such as EMS devices, VVO and more recently 3V0. The total for EMS, VVO and 3V0 in the FY21 forecast and FY22 budget are $2.9 million and $5.9 million, respectively.

c. Please see Attachment PUC 1-5-1 for the projects that make up the FY 2022 proposed spending, an explanation of why each of the programs and projects are proposed, and the prioritization. Please note that the attachment totals to the revised Reliability total of $9.450 million. Please see Attachment PUC 1-5-2 for specific project details for the New Lafayette project.

   In regard to the priority rankings, the Company respectfully submits that all of the System Capacity & Performance projects proposed in the FY 2022 ISR Plan fall within the same top priority tier and that the Company's decision to include the projects and associated budgets within the Plan is an integral component of the Company's statutory responsibility to propose an investment and spending plan for review by the Commission that is reasonably needed to maintain safe and reliable distribution service over the short and long term.

Prepared by or under the supervision of: Patricia C. Easterly and Caitlin Broderick

Priority	Project	Reason for Proposal	FY 2022 Budget $'000s
1	3V0	As a result of Distributed Generation (DG) penetration, including small scale sites, protection issues are emerging that are becomming increasingly difficult to assign to a specific DG site. This program's prioritization considers the DG interconnection queue. Includes some remaining mobile 3V0 spending from FY 2021.	$1,434
2	EMS Expansion	Projects to install Energy Management System (EMS) devices improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies	1,303
3	New Lafayette	Although the Lafayette project is in the system capacity and performance spending rationale, it also has significant asset condition drivers. The project solves loading issues in the area and addresses asset condition and reliability issues on the supply lines to the existing Lafayette substation.	1,857
4	Cutout Mounted Recloser Program	This category includes the annual cutout mounted recloser (CMR) program. This program recommends the installation of single phase cutout mounted reclosers at targeted locations on primary overhead lines across the Company's distribution network	133
5	Blankets	The Company also has blanket projects that are established to ensure that local field engineering and operations can resolve system and equipment loading and reliability issues in an efficient and effective manner.	1,395
6	VVO	The intent of this project is to flatten and lower the feeder voltage profile using additional voltage monitors along the feeder and centralize control of the regulating devices based on real time system performance. The lowering of feeder voltages benefits customers by reducing the demand and energy usage.	3,228
7	Flood Contingency Plan	This project includes installing Flood Barriers to protect substation equipment at locations at high risk to flooding in the event of a 100-year flood. It also includes the purchase and preparation of pumping systems for substation yards for use in the event of a major flood. Installation includes flood barriers around substations equipment/yard except egress points.	45
8	Other Projects	This category addresses small targeted reliability issues.	57
	Reliability - SC&P - total		**$9,450**

New Lafayette Substation – Project Summary

Distribution Related Project Number(s):	C081740 - Lafayette Substation (T-Line) C081691 - Lafayette Substation (T-Sub) C081675 - Lafayette Substation (D-Sub) C081683 - Lafayette Substation (D-Line) C081663 - 3312 ROW Removals (T-Line) C081685 - 84T3 ROW Removals (D-Line)
Substation(s) / Feeder(s) Impacted:	Lafayette – 30F1, 30F2 Davisville – 84T3 Kent County – 3312
Voltage(s):	12.47 kV, 34.5 kV
Geographic Area Served:	North Kingstown, RI
Summary of Issues:	A comprehensive study of the South County East area was performed to identify existing and potential future distribution system performance concerns. The major concerns documented in the South County East Study report are summarized below: Reliability: • Tower Hill is a single transformer station with four 12.47 kV feeders and approximately 36 MW of load. For loss of the station transformer, there is approximately 19 MW of unserved load exposure during peak load conditions (or 495 MWh of exposure). The unserved load exposure exceeds the recommendations in the distribution planning criteria • Loading on the Bonnet T2 transformer is projected to be loaded above SN limits. • Three feeders are projected to be loaded above Summer Normal (SN) limits and four feeders have been calculated to have unserved load exposure in excess of the distribution planning criteria. • The 3312 line has reliability concerns. Over the last three years the 3312 line has experienced a number of outages. Generally, an outage on the 3312 line resulted in an outage on the under-built 12.47kV circuit. Asset Condition: • Majority of the 3312 line (8.6 miles) and the 84T3 line (8.7 miles) supplying Lafayette substation have asset issues. Each of these lines has substantial right-of-way sections which would increase direct replacement costs. • Large portions of these lines are installed in rights-of-way (ROW) with limited access or through backyards with restricted access. The ROW contains wetlands and water crossings. There will be anticipated wetland challenges along with restrictive backyard construction. • A visual inspection of the lines identified significant deterioration on the pole plant and associated equipment. Age of more than 40% of the poles on the 3312 and 84T3 lines are 60 years or older.

Recommended Plan	The recommend plan is to build a new 115/12.47 kV substation at the existing Lafayette substation site. The station shall be built with 3V0 protection to accommodate existing and proposed distributed generation in the area. Details of the plan are: • Build a new open air, low profile, breaker-and-one-half substation consisting of a single 115/12.47 kV 24/32/40 MVA transformer, four regulated feeders, and one 7.2 MVAr station capacitor bank with of two 3.6 MVAr stages. • Install new single span 115 kV tap line from L190 to supply the new Lafayette substation. Install one loadbreak switch to the north in the L190 mainline. • Install a manhole and ductline system for the feeder getaways out to city streets. The feeders will follow existing overhead routes and generally utilize existing overhead infrastructure. The new feeders will provide capacity to convert few commercial customers to 12.47 kV and allow for the retirement of the 34.5 kV system that supplies Lafayette. The retirement of the 34.5 kV supply to Lafayette address the asset condition concerns and mitigates the access issues associated with the right-of-way. • Remove the existing 34.5/12.47 kV station at Lafayette once the new station is in-service. This plan eliminates approximately 17-miles of sub-transmission lines. The retirement of these assets results in the most economical option that is adequate to resolve the area concerns. These lines have significant asset condition and reliability concerns. Total Cost = $16 million (includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes).
Current Status and Expected In-Service Date	Current Status – Step 4.3 – Develop & Sanction Expected In-Service – See Detailed Budget for System Capacity & Performance and Asset Condition Projects.
Alternatives:	<u>Alternative 1</u> - New Mainsail Dr 115/12.47 kV Station: The major component of this plan is a new 115/12.47 kV substation in Quonset to be built on a green field site and the refurbishment of the 34.5 kV supply system to Lafayette substation. The substation site will have to be acquired from either the Quonset Development Corporation (QDC) or some other private party. The proposed substation would consist of a single 115/12.47 kV 40 MVA LTC transformer and four feeders. Acquiring a substation site in Quonset may be challenging. The site would have to be in close proximity to the transmission system and land availability is very limited. A site owned by the Quonset Development Corporation (QDC) may be a potential candidate; however, the QDC is unlikely to sell this site for substation development since the area has been targeted for economic development. This option requires the refurbishment of the 34.5 kV supply system to Lafayette substation. Large sections of the right-of-way have wetlands and potentially sensitive vegetation. There will be anticipated wetland challenges along with restrictive backyard construction. The lines were built in the 1930's and a visual inspection identified significant deterioration of the pole plant and associated equipment. A refurbishment in place would leave all the right of way challenges unaddressed. If this option is to be pursued, it is recommended that relocating these lines to the roadway be further explored and developed. Conceptual estimates to

	relocate a portion of these lines to the roadway have been developed but not included in plan costs. Total Cost = $37 million (includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes) Alternative 2 - Expansion of Old Baptist Station: The major component of this plan is to expand Old Baptist substation by installing a third bay, two additional feeders, and station capacitor banks. This plan would also refurbish the 34.5 kV supply to Lafayette substation. Similar to Alternative 1, this option requires the refurbishment of the 34.5 kV supply system to Lafayette substation. Large sections of the right-of-way have wetlands and potentially sensitive vegetation. There will be anticipated wetland challenges along with restrictive backyard construction. The lines were built in the 1930's and a visual inspection identified significant deterioration of the pole plant and associated equipment. A refurbishment in place would leave all the right of way challenges unaddressed. If this option is to be pursued, it is recommended that relocating these lines to the roadway be further explored and developed. Conceptual estimates to relocate a portion of these lines to the roadway have been developed but not included in plan costs. Total Cost = $26 million (includes all costs with transmission, distribution, operations & maintenance, and removal values for alternative comparison purposes)
Long Range Plan Alignment	South County East Study (March 2018).

PUC 1-6

Request:

Referring to the Capital Spending Key Driver table on Bates page 94, the budget for meters in FY 2021 was $2,995,000 but the forecast of actual is only $2,111,000.

a. Please provide the number of meters (and the associated dollar value) the Company forecasted it would install in FY 2021, compared to the number actually installed.
b. Of the number of meters in the FY 2021 forecast, please identify the number of meters (and associated actual dollar value) that went to inventory, if any, and
c. For FY 2022, please identify the number of meters (and associated actual dollar value) the Company forecasts it will install compared to purchases that will go to inventory, if any.

Response:

a. For the FY 2021 Ocean St-Dist-Meter program, the Company forecasted it would meter change/install 14,809 meters with a capital budget of $1.090M. Through December of FY 2021 the Company has meter change/installed 5,654 meters.

b. For the FY 2021 Narragansett Meter Purchase program, the Company has purchased 8,715 meters through December FY2021. Prior to delivery to support field operations, new meter shipments are received from the manufacturer at the Company's meter lab and processed, tested, and placed in inventory. The 8,715 meters purchased in FY 2021 are currently being used to support FY 2021 field operations. The meters the Company purchased in FY 2021 are expected to be installed by end of FY 2021.

c. For the FY 2022 Ocean St-Dist-Meter program, the Company forecasts it will meter change/install 15,246 meters with a capital budget of $800k.

   For the FY 2022 Narragansett Meter Purchase program, the Company forecasts the need to purchase 14,000 meters to support operational workplans. The meter purchases will initially be placed in inventory at the Company's meter lab before being used to support FY 2022 operational workplans.

   For the FY 2022 RI Landline Meter Replacement program, the Company forecasts it will purchase and install 210 meters to support the program. The meter purchases will initially be placed in inventory at the Company's meter lab before being used to support the FY 2022 RI Landline Meter Replacement work.

   The FY 2022 RI Meter Reprogramming program is a demand meter field reprograming effort that requires no new meter purchases or installations to support the program.

Prepared by or under the supervision of: Nicholas Ritts

PUC 1-7

Request:

Referring to the Capital Spending Key Driver table on Bates page 94, please provide an explanation and evidentiary support for the FY 2022 budget forecast of $3,375,000 for distribution meters when (i) the Company has never reached that level of spending on meters in any ISR dating back to 2011, (ii) spending in FY 2021 is expected to be only $2,111,000, and (iii) the economic impact of the pandemic is expected to continue for many months longer in calendar year 2021.

Response:

(i) The Company's FY 2022 budget forecast includes the purchases as described in the response to PUC 1-6, part c ($1.975M), but also includes walk-in replacement work ($600k), and the associated field labor ($800k). The FY 2022 budget forecast for walk-in replacement work has led to a higher anticipated level of spending than historical years.

(ii) Company pandemic social distancing requirements led to a decrease in customer Meter Service (CMS) field activity over the first two quarters of FY 2021. As a result, the Company's meter lab scaled back meter orders over the first two quarters of FY 2021 to align with CMS field activity. This has resulted in a lower forecasted spend for FY 2021.

(iii) As of December, CMS has resumed their normal meter change/install work load and the meter lab is experiencing an uptick in orders to support field work over the remainder of FY 2021. This is expected to continue into FY 2022.

Prepared by or under the supervision of: Nicholas Ritts

PUC 1-8

Request:

Referring to the category labeled "Ocean St-Dist-Damage&Failure Blnkt," shown on Attachment 2 of Section 2, please explain the specific assumptions used in developing the budget of $8,925,000, including a list of all known projects that the Company expects to undertake within this category in FY 2022. For projects in this category, please attempt to categorize the types of investments typically undertaken. Please provide actual spending to budget for the last five fiscal years under this budget category, including FY 2021.

Response:

The table below summarizes spending in the Damage/Failure Blanket for the past five years.

Project Number	Project Description		FY 2017	FY 2018	FY 2019	FY 2020	FY 2021 (Forecast)
COS0014	Ocean St-Dist-Damage&Failure Blankt	Actuals	$10,172,757	$10,427,025	$8,424,098	$9,984,056	$10,200,000
COS0014	Ocean St-Dist-Damage&Failure Blankt	Budget	$8,243,000	$8,781,326	$10,445,000	$10,330,000	$8,520,000

Blanket funding projects consist of many work orders that are typically standard construction, and of short duration and small cost. The specific work that will be undertaken and charged in the Non-Discretionary category of Damage/Failure Blanket is generally not known ahead of time and is reactive in nature; therefore, the budget in this category is usually derived based on trending actual historical costs and not on specific projects. However, the Company did not use trending analysis to estimate the FY 2022 budget for this blanket project because the Company is in the process of implementing new processes related to this blanket project. Only work under a more-narrow definition of failed assets are considered Non-Discretionary and other work is considered Discretionary. At the time we developed the FY 2022 budget, this new process was getting underway and we did not know if trending actuals would be accurate. Therefore, we based the FY 2022 budget on the FY 2021 budget ($8,520,000) with an approximately 5% increase for general cost increases.

The categories of investments generally undertaken in this project include the replacement of any capital unit of plant that has been damaged or has failed and is no longer in service. Examples of this equipment would be reclosers, load breaks, air breaks, pad-mounted or overhead transformers, conductor such as overhead wire and underground cable, and poles. In the event the equipment is damaged or fails, there is typically an unplanned emergency customer outage condition resulting which requires us to make repairs. Some replacements are completed immediately with like-for-like equipment and some work requires temporary repairs or restoration and the permanent repair requires engineering support.

PUC 1-9

Request:

Referring to the category labeled "Ocean St-Dist-New Bus-Comm Blanket," shown on Attachment 2 of Section 2, please explain the specific assumptions used in developing the budget of $5,931,000, including a list of all known projects and costs. For projects in this category, please attempt to categorize the types of projects investments typically undertaken. Please provide actual spending to budget for the last five fiscal years under this budget category, including FY 2021.

Response:

See the New Business Commercial portion of the response to PUC 1-3 for detail regarding the assumptions used in developing the budget of $5,931,000. The categories of work performed under the blanket include new services, line extensions to serve new customer, conversion to serve new customer or substantial new load, addition of one or two new phases to serve new three phase load, riser & riser poles for new underground service and increase size of service due to added load.

See the table below for budget and actual spending for the last five years.

		FY2016	FY2017	FY2018	FY2019	FY2020	FY2021 - 9MTD	FY2022
COS0011 - Ocean St-Dist-New Bus-Comm Blanket	Budget	3,200,000	3,380,000	3,900,000	4,103,000	4,580,000	5,655,000	5,931,000
	Actuals	3,749,326	3,422,187	3,504,856	4,630,356	5,679,973	4,045,130	
	Variance -	(549,326)	(42,187)	395,144	(527,356)	(1,099,973)	1,609,870	

Prepared by or under the supervision of: Patricia C. Easterly

PUC 1-10

Request:

Did the Company consider ways to mitigate rate impacts on ratepayers by deferring projects that are not immediately needed, when it developed its discretionary spending budget? If so, please explain all the factors that were considered and how it affected the final proposed budget. If not, why not?

Response:

Yes, the Company did consider ways to mitigate rate impacts as the proposed plan was developed. The Company considered a balance of system needs, customer expectations related to service reliability and costs in the development of its discretionary budget at a portfolio level. The Company did defer projects and looked for opportunities to defer projects that had less urgent system risks and those projects are not included in the current annual plan. For instance, Energy Management System (EMS) projects, underground cable and underground residential development (URD) projects, are associated with multi-year programs that we have extended beyond the original proposed program life. We did that by prioritizing specific work done under these programs and by advancing only the highest priority EMS, underground cable, URD and Asset condition projects within the annual plan.

In addition, some projects result from long term planning studies or other adhoc evaluations of the Company's system based on electric system planning guidelines. These projects address either existing or anticipated system needs and were only advanced when those system issues need to be resolved to ensure safety or avoid service reliability degradation or damaged equipment. Other projects were determined by asset and reliability programs and were prioritized to maintain or slightly improve current levels of risk. Deferral of any of these projects could result in additional risks and possibly degraded safety and reliability.

As indicated above, the factors considered include ensuring the Company meets system planning criteria, asset condition information, reliability information, work driven by state policies and work driven by other technical system needs. These factors were considered in studies and programs described above which ultimately make up the final discretionary proposed budget.

Furthermore, the Company worked in cooperation with the Division prior to submitting an annual plan with the Commission. During this period, the Company considered the Division's input and sought to address any cost concerns that were raised by the Division. For example, in this year's plan, $6.7 million was removed to be deferred for future consideration through discussions with the Division.

Prepared by or under the supervision of: Caitlin Broderick

PUC 1-11

Request:

Referring to the Capital Spending Key Driver table on Bates page 94, please explain the investment of $1 million identified for Distributed Generation in FY 2022, clearly indicating what types of unreimbursed distributed generation customer requests the Company expects to incur. Please also provide a list of the projects (separate but anonymized) and their respective costs (type and amount) to support the $1 million that is expected to be incurred for FY 2021.

Response:

The Company collects Contribution In Aid of Construction (CIAC) from interconnecting customers in advance of construction. The first payment (for engineering design and permitting) is required upon execution of the interconnection service agreement and the balance is due prior to the start of construction. For projects with CIACs exceeding $1 million, the Company has allowed two payments with the last payment still due prior to construction. Consequently, it is possible that payments received will span calendar years and, likewise, based on the complexity of the interconnection, it is also possible the costs incurred will span multiple calendar years.

Until FY2021 the Company's practice was to reflect CIAC received from customers as a credit to the capital project work order when first received and capital spend would offset the credit balance as charges are incurred which meant in any one year the annual work order capital activity could be debit or credit. During FY2021, the Company began implementing a new process at the work order level where by the CIAC is initially recorded in deferred revenue and subsequently reduced and transferred to capital to offset the construction costs when incurred on monthly basis. Therefore, the Company expects that the net capital activity for any fiscal year will be the net difference between capital expenditures and CIACs received, which the Company expects to be a minimal amount.

Implementation of this process is expected to be completed by fiscal year end 2021. Since this process implementation is still underway the Company used the same estimate for FY2022 as for FY 2021, which was $1 million.

Prepared by or under the supervision of: Patricia C. Easterly

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PUC 1-12

Request:

Referring to Bates page 91, please provide a more detailed explanation with specificity, supporting the $1.3 million budget for Non-infrastructure, including the timing of spending and the nature of the equipment that is being retired and replaced by the new equipment.

Response:

The non-infrastructure category of spending is for capital expenditures that do not fit into one of the other spending rationales. This capital spending is necessary to run the electric system, such as general and telecommunications equipment. See a summary below of the individual projects in this category.

Costs included in the General Equipment Blanket and Telecoms projects relate to small equipment such as field equipment, large tools, radios, alarms, and communications shelters that are purchased throughout the year.

In FY 2022 and FY 2023, the Company has proposed increased non-infrastructure spending related to the purchase and installation of communication equipment for substations due to the retirement of Verizon's DS0 communications lines. The Company has proposed an additional $800,000 per year in FY 2022 and FY 2023 to purchase and install JMUX devices, DC-AC inverters and wall mount brackets inside several electric substations. These devices will be installed within the Company substations in coordination with Verizon as they convert DS0 circuits to T1 circuits. The work will ensure continued operation of substation protection systems and allow for telecommunication operations at each station. Verizon's timing schedule for DS0 retirements is communicated to National Grid on a year by year basis. Until Verizon communicates the expected retirements, the exact timing of the work is not known.

The table below shows the details available by project.

Project #	**Project Description**		**FY 2022** $'000		**Timing of work**
COS0006	Ocean St-Dist-Genl Equip Blanket		$250		Throughout the year
C040644	Telecom Small Capital Work - RI		$260		Throughout the year
C086391	Verizon Copper to Fiber Conversions		$800		Pending notification from Verizon
			$1,310		

PUC 1-13

Request:

Referring to the Capital Spending Key Driver table on Bates page 94,

(a) please identify all the items forecasted for installation that comprise the $2.7 million budget for FY 2022 in the category of "Strategic DER Investments,"
(b) please identify all the expenditures that are expected to have occurred in FY 2021, comprising the forecasted $2.4 million, and
(c) please explain why the FY 2021 budget is forecasted to be exceeded by $413,000.

Response:

(a) The $2.7M budget for FY2022 in the category of Strategic DER Investments includes:

- Approximately $150,000 Capex for Feeder Monitors on Chopmist substation feeders
- Approximately $450,000 Capex for Feeder Monitors on Hopkins Hill substation feeders
- Approximately $20,000 for engineering and design of full implementation of advanced devices at Chopmist substation.
- The remaining approximately $2.050M is being reserved to respond to reliability or performance issues that may emerge on the system in FY2022 that would require mitigations immediately and cannot be attributed to specific DER interconnections. For example, overloaded conductor and/or high voltage that could potentially result in equipment damage and/or customer outages. If these issues do arise and the estimated solution is significant, the Company will review the recommendation with the Division before implementation.

The chart below includes the forecast for Strategic DER Investments in FY2022.

Scope	**FY2022 Budget (capex)**
Chopmist Substation Feeder Monitors	$150,000.00
Hopkins Hill Substation Feeder Monitors	$450,000.00
Chopmist Advanced Devices engineering	$50,000.00
Strategic DER Emerging Issues	$2,050,000.00
TOTAL	$2,700,000.00

Prepared by or under the supervision of: Caitlin Broderick

PUC 1-13, page 2

(b) The forecasted $2.4M in FY2021 has been updated to approximately $20,000 since the FY2022 ISR plan was filed. Originally, the Company planned to fully implement all advanced devices at the Chopmist substation in FY2021. The scope of this work is included in Division data request response R-I-11 and was estimated at approximately $2.6M. The Company planned to address the emerging voltage issues at Chopmist substation in FY2021, but the analysis took longer than originally anticipated. The Company developed a revised plan based on negotiations with the Division. The Division requested the Company hold off on full implementation of advanced devices at Chopmist substation until the PUC has reviewed and approved the Company's Grid Modernization Plan (GMP). The Company and the Division were able to reach a negotiated consensus on the scope of work to be undertaken, which was revised to the installation of Feeder Monitors only at Chopmist and Hopkins Hill substation in FY2022 and engineering for full implementation of advanced devices at Chopmist substation in order to be ready for potential construction in FY2023. Therefore, the revised strategy for Strategic DER Investments in FY2021 would be for engineering and design of Feeder Monitors at Chopmist and Hopkins Hill substation and for advanced devices on the Chopmist feeders.

(c) The Company was planning on full implementation of advanced devices at the Chopmist substation in FY2021. As a result of negotiated agreements with the Division on the FY2022 ISR plan, the FY2021 forecast for Strategic DER Investments was reduced from the second quarter forecast of $2.4 million to approximately $20,000 for engineering only. Spending currently forecasted for FY2021 will be on the engineering for Feeder Monitors at Chopmist and Hopkins Hill substations and potentially some engineering on advanced devices at Chopmist substation.

PUC 1-14

Request:

Referring to Bates pages 60-61, please identify any investments in the category of "Strategic DER Investments" that are contingent upon Commission approval of the Company's Grid Modernization Plan filed in January 2021. Why are the investments described on page 61 categorized as mandatory spending instead of discretionary spending?

Response:

The Company has proposed $2.7 million in the FY2022 ISR Plan to install feeder monitoring sensors on feeders at two substations, progress engineering for full deployment at one substation and to accommodate work that may emerge as a result of system performance or reliability issues from DER interconnections.

Consistent with the Commission's requirements in approving the FY2021 Plan, all such investments are to be classified as Non-Discretionary until the Company's Grid Modernization Plan (GMP) is approved since it is recognized that there may be a need to make such investments on a reactive basis. If the FY2022 ISR Plan is approved as proposed, none of these investments would be contingent upon Commission approval of the Company's Grid Modernization Plan filed in January 2021. Upon approval of the GMP, the classification for this type of work will shift from Non-Discretionary to the Discretionary category as implementation would be considered pro-active in nature and, therefore, Discretionary.

Prepared by or under the supervision of: Caitlin Broderick and Patricia C. Easterly

PUC 1-15

Request:

Referring to the Capital Spending Key Driver table on Bates page 94, please itemize all of the expenditures that are included in the category of Transformers & Related Equipment and explain why the budget proposes an increase of over $700,000 for FY 2022, compared to forecasted expenditures in FY 2021.

Response:

Costs in the category of Transformers & Related Equipment relate to the purchase of Transformers, Capacitors, Regulators, and Network Protectors. The budget for this category is based on a historical trending analysis with consideration of future expectations which are challenging to predict. However, as demonstrated by the increasing trend of installed quantities of these devices shown on Attachment PUC 1-15, we believe the Company will be required to purchase more in this category for FY 2022 than the previous FY 2021 forecast. As explained below, the historical trends coupled with balancing the need to ensure supply availability to avoid or minimize customer interruptions, and managing inventory with increasing lead times combine to warrant the amount proposed even with somewhat uncertain future specific needs.

The data used to base the estimate for the upcoming fiscal year budget is the 12 month Moving Annual Totals (MAT) through July 2020 (ISR Pre-filing draft submitted to the Division in August 2020). The table below summarizes the quarterly MAT data from March 2019 through June 2020 and monthly thereafter. An estimate for inflation is added to derive the budget for FY 2022, see summary below the MAT table.

		COST GROUPING					
PROJECT DESCRIPTION	Values	ALL TRANSFORMERS	CAPACITOR	PROTECTOR	REGULATOR	Other Costs - OH, CIACs Etc	Grand Total
Narragansett Transformer Purchases	MAT-201903	3,429,541	303,884	-	181,420	707,610	4,622,455
	MAT-201906	3,456,394	225,066	175,137	138,524	661,581	4,656,702
	MAT-201909	3,369,260	212,486	175,137	46,736	701,940	4,505,559
	MAT-201912	3,559,775	190,411	350,217	11,684	821,208	4,933,294
	MAT-202003	3,528,562	260,437	350,217	139,920	877,538	5,156,674
	MAT-202006	3,228,719	289,347	175,080	139,920	864,200	4,697,266
	MAT-202007	3,105,601	355,417	175,080	139,920	861,677	4,637,696
	MAT-202008	3,112,197	511,920	175,080	139,920	896,769	4,835,886
	MAT-202009	3,196,360	498,879	175,080	183,599	936,487	4,990,405
	MAT-202010	2,885,158	492,089	175,080	198,588	875,681	4,626,596
	MAT-202011	2,904,291	523,416	117,176	198,588	864,221	4,607,691
	MAT-202012	2,738,664	548,256	29,965	239,691	834,387	4,390,963
					MAT as of July		4,637,696
					Estimate used for FY 2022		4,770,000

PUC 1-15, page 2

FY2022 Transformer Purchase Blanket Budget Estimate Calculation

Blanket Uninflated FY2022 Estimate	**4,770,000**	
Adjustment for Inflation (1.5%), Economic Increase (1%), Materials (2%) etc.	**145,000**	**3.0%**
	4,915,000	

Purchases are driven by installations and the necessity to maintain specified level of stock to be kept on hand. Because of the association with installations and because there is not a perfect match of installations to purchases by year, we have summarized installed quantities in Attachment PUC 1-15 for each asset category in this project for the years from FY 2017 through YTD FY 2021 to support the increasing purchasing trend. The Company has seen a significant increase in installations of all equipment purchased over the 5 years represented.

Increases in transformer installations are caused by projects in the Discretionary category, such as Chase Hill, New London, and Aquidneck projects and the Metal Clad substation projects through FY 2021. FY 2022 installations for project requirements are expected to continue for the Providence Phase 1A and Phase 1B projects. Increases in the Non-Discretionary category are driven by the New Business blankets for both Commercial and Residential categories as well Distributed Generation projects. We assume similar requirements for projects in these categories in FY 2022. While there are trending decreases in the damage/failure category, it is difficult to predict the future requirements for that category.

Increases in installations of capacitor, regulators, and network protectors are primarily driven by VVO projects but there are also installations in other portions of the portfolio. In addition, because of the long lead time for regulators, there will be an increase in the required level of emergency stock from 1 to 9 units that will also be part of the FY 2022 purchases.

The forecast for FY2021 on Bates page 94 was based on a different method than used to estimate the FY 2022 budget. The forecast on page 94 was the second quarter forecast using actuals through September and monthly budget thereafter so does not reflect the potential changes that could occur from October through March 2021, which is what the 12 MAT method attempts to estimate.

Please see Attachment PUC 1-15-1 for a table showing installations and purchases of transformers, capacitors, regulators and network protectors for FY 2017 through December 2020.

Prepared by or under the supervision of: Patricia Easterly

As of 2/5/21

TRANSFORMERS

	FY17	FY18	FY19	FY20	FY21 to date	Total - FY17-FY21 to date
Installed by Spending Rationale						
Syst Cap & Perf	315	324	453	484	112	1,688
Asset Condition	295	87	132	224	287	1,025
Cust Req/Public Req	507	620	801	818	511	3,257
Damage/Failure	516	525	406	435	341	2,223
WR# not identified	(11)	2	6	(6)	44	35
Installations per GIS	1,622	1,558	1,798	1,955	1,295	8,228
Purchases	1,052	1,314	2,435	2,487	1,033	8,321

CAPACITORS

	FY17	FY18	FY19	FY20	FY21 to date	Total - FY17-FY21 to date
Installed by Spending Rationale						
Syst Cap & Perf	5	13	22	36	-	76
Asset Condition	2	-	-	2	3	7
Cust Req/Public Req	2	-	5	5	-	12
Damage/Failure	5	1	3	6	3	18
WR# not identified	3	-	-	3	-	6
Installations per GIS	17	14	30	52	6	119
Purchases	-	4	59	39	65	167

REGULATORS

	FY17	FY18	FY19	FY20	FY21 to date	Total - FY17-FY21 to date
Installed by Spending Rationale						
Syst Cap & Perf	14	-	4	-	6	24
Asset Condition	-	-	-	-	-	-
Cust Req/Public Req	-	3	-	1	3	7
Damage/Failure	-	3	-	1	1	5
WR# not identified						-
Installations per GIS	14	6	4	2	10	36
Purchases	-	-	16	12	7	35

NETWORK PROTECTORS

	FY17	FY18	FY19	FY20	FY21 to date	Total - FY17-FY21 to date
Installed by Spending Rationale						
Syst Cap & Perf		-				-
Asset Condition		1			1	2
Cust Req/Public Req		1		1	4	6
Damage/Failure				2		2
WR# not identified				1	1	2
Installations per GIS	-	2	-	4	6	12
Purchases	-	-	-	13	1	14

PUC 1-16

Request:

Please expand the table on Bates 96 and 97 which includes an itemization of the FY 2022 asset condition spending of $40.183 million. The expansion should include:

a. Location of work
b. Risk assessment score
c. FY 2022 revenue requirement associated with the capital expenditure.

Response:

Please see Attachment PUC 1-16-1 for a table itemizing the total FY 2022 asset condition spending of $40.483 million by project, location, risk score and FY 2022 revenue requirement. The Company has employed the same methodology described in response to Data Request PUC 1-2 to calculate the FY 2022 revenue requirement by line item as shown in Column (g) of the Attachment.

	Project #	Project Description	Location of Work	Risk Assessment	FY 2022 Plan Spend	Target Placed In-Service FY 2022 Including COR	FY 2022 Revenue Requirement
	(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f) * Line 72
1	C032019	Batts/Chargers NE South OS RI	Various	40	$150,000	$118,788	$6,462
2	C036527	Westerly Flood Restoration (D-Sub)	Westerly	42	($2,105)	($8,076)	($439)
3	C047378	IRURD Willowbrook	Cranston	36	$362,736	$217,683	$11,842
4	C047394	IRURD Tanglewood	West Warwick	36	$650,000	$390,036	$21,218
5	C047829	IRURD High Hawk	East Greenwich	36	$16,758	$104,066	$5,661
6	C049356	IRURD Silver Maple Phase 2	Coventry	36	$150,788	$90,696	$4,934
7	C049462	IRURD SIGNAL RIDGE, EAST GREENWICH	East Greenwich	36	$738,000	$447,898	$24,366
8	C050070	IRURD Placeholder RI	Various	n/a	($212,000)	$252,000	$13,709
9	C050299	IRURD Eastward Look	Narragansett	36	$168,000	$101,041	$5,497
10	C051205	Dyer St replace indoor subst D-SUB	Providence	45	$4,431,952	$9,206,842	$500,852
11	C051211	Dyer St replace indoor subst D-LINE	Providence	45	$5,285,000	$3,035,833	$165,149
12	C051212	South St repl indoor subst D-SUB	Providence	48	$300,000	$300,000	$16,320
13	C051213	South St repl indoor subst D-LINE	Providence	48	($2,655)	$0	$0
14	C055215	Westerly Flood Restoration (D-Line)	Westerly	42	($2,243)	($47)	($3)
15	C055343	RI UG Cable Placeholder	Various	n/a	$895,000	$447,168	$24,326
16	C055359	RI UG Cable Repl Program - Fdr 79F1	Narragansett	36	$220,000	$141,303	$7,687
17	C055364	RI UG Cable Repl Program - Fdr 13F6	Providence	36	$337,569	$205,859	$11,199
18	C055370	RI UG Cable Repl Prog Fdr 1144/1109	Narragansett	36	$460,000	$281,133	$15,294
19	C055371	RI UG Cable Repl Prog Fdr 1142/1105	Narragansett	36	$426,558	$291,050	$15,833
20	C055392	RI UG Cable Repl Program - Secondar	Various	36	$500,000	$1,291,163	$70,239
21	C056947	IRURD Juniper Hills WWarwick	West Warwick	36	$374,000	$247,948	$13,488
22	C057882	IRURD Chateau Apts URD Rehab	Cranston	36	$166,000	$100,232	$5,453
23	C057903	IRURD Western Hills Village URD-	Cranston	36	($1,918)	($959)	($52)
24	C057906	IRURD Woodvale Estates URD-	Johnston	36	$15,000	$9,541	$519
25	C058045	IRURD-Tockwotton Farm_TF Road.	North Kingstown	28	$169,680	$112,190	$6,103
26	C058046	IRURD-Tockwotton Farm_RM Way.	North Kingstown	28	($3,404)	($1,202)	($65)
27	C065830	Recloser Replacement Program RI	Various	36	$200,000	$10,000	$544
28	C069166	Pawtucket 1 Breaker Replacement	Pawtucket	41	$25,000	$112,526	$6,121
29	C074307	RI UG 79F1 duct Charles & Orms Sts	Providence	36	$728,587	$847,233	$46,089
30	C076289	IRURD Pequaw Honk URD RI-L Compton	Little Compton	36	$234,022	$403,949	$21,975
31	C078474	Franklin Sq Sub_1105 & 1109 NW	Providence	14	$439,929	$283,224	$15,407
32	C078488	RI DFP100 Relay Replacement Project	various	34	$40,043	$147,771	$8,039
33	C078734	Ph 1A - ProvStudy Admiral St 4&11kV Convert	Providence	35	$3,743,061	$3,000,163	$163,209
34	C078735	Ph1B - ProvStudy New Admiral St 12kV D-Sub	Providence	35	$1,438,054	$14,526	$790
35	C078796	Ph1B - ProvStudy Admiral St-Rochamb D-Line	Providence	35	$209,500	$24,100	$1,311
36	C078797	Ph1B - ProvStudy Admiral St-Rochamb D-Sub	Providence	35	$500,530	$26,496	$1,441
37	C078800	Ph 1A - ProvStudy Clarkson-Lippit12kV DLine	Providence	35	$1,222,937	$2,452,040	$133,391
38	C078802	Ph 1B - ProvStudy Olneyville 4kV D-Line	Providence	35	$203,532	$57,406	$3,123
39	C078803	Ph 1B - ProvStudy Admiral St 12kV MH&Duct	Providence	35	$272,326	$300	$16
40	C078804	Ph 1B - ProvStudy Admiral St 12kV Cables	Providence	35	$271,303	$0	$0
41	C078805	Ph 4 - ProvStudy Knightsville 4kV Convert	Providence	35	$220,000	$39,481	$2,148
42	C078806	Ph 4 - ProvStudy Knightsville 4kV D-Sub	Providence	35	$275,000	$0	$0
43	C078921	RI UG Cable Repl Program - Fdr 1158	Providence	36	$12,699	$7,349	$400
44	C078923	RI UG Cable Repl Program - Fdr 1160	Providence	36	$299,699	$190,787	$10,379
45	C078926	RI UG Cable Repl Program - Fdr 1162	Providence	36	$280,000	$330,275	$17,967
46	C078928	RI UG Cable Repl Program - Fdr 1164	Providence	36	$12,699	$7,349	$400
47	C078931	RI UG Cable Repl Program - Fdr 1166	Providence	36	$418,000	$496,702	$27,021
48	C079331	Viper Recloser Replacement Pgm 1-RI	Various	6	$165,000	$17,000	$925
49	C081006	Franklin Sq Breaker Replacement	Providence	39	$1,803,905	$1,857,905	$101,070
50	C081341	IRURD Woodland Manor-Coventry	Coventry	24	$481,476	$668,123	$36,346
51	C082439	Franklin Sq-Replace 11kV Sub Equip	Providence	39	$48,532	$329,724	$17,937
52	C086514	RI GE Type U Bushing Replacement	Providence	41	$275,000	$8,000	$435
53	C083782	Replace 12.47 Breakers Drumrock 14	Warwick	39	$196,448	$6,000	$326
54	C084172	IRURD Jencks Hill, Lincoln RI	Lincoln	34	$270,372	$171,363	$9,322
55	C084377	IRURD Governor's Hills, RI	Warwick	36	$402,786	$262,270	$14,267
56	C084378	IRURD Frenchtown Green, RI	East Greenwich	36	$253,527	$167,505	$9,112
57	C084965	IRURD Sandy Point Farms Phase 2	Portsmouth	36	$463,000	$359,659	$19,565
58	C085005	RI UG Cable Repl Program - Fdr 1139	Providence	36	$409,000	$252,500	$13,736
59	C085553	RI Repl ACNW Vault Vent Blowers	Various	17	$400,000	$240,014	$13,057
60	COS0017	Ocean St-Dist-Asset Replace Blankt	Various	49	$3,399,000	$3,972,594	$216,109
61	COS0026	OS-Dist-Substation Asset Repl Blnk	Various	34	$193,000	$191,178	$10,400
62	C026281	I&M - OS D-Line OH Work From Insp.	Various	45	$2,875,000	$3,127,970	$170,162
63	C080076	I&M - OS Sub-T OH Work From Insp	Various	45	$125,000	$75,161	$4,089
64	C053657	Southeast Substation (D-Sub)	Pawtucket	44	$787,000	$30,053	$1,635
65	C053658	Southeast Substation (D-Line)	Pawtucket	44	$1,060,000	$16,234	$883
66	C055683	Pawtucket No 1 (D-Sub)	Pawtucket	44	$235,000	$3,418,519	$185,967
67	Total				$40,482,685	$41,005,635	$2,230,707

Project #	Project Description	Location of Work	Risk Assessment	FY 2022 Plan Spend	Target Placed In-Service FY 2022 Including COR	FY 2022 Revenue Requirement
68	FY22 Depreciation, Return and Taxes associated with FY22 investment		$3,644,310			
69	FY22 Property tax associated with FY22 investment		$2,566,000			
70	Total FY22 revenue requirement associated with FY22 investment		$6,210,310			
71	Total FY22 Capital Placed into Service plus Cost of Removal (COR)		$114,112,000			
72	Ratio of Revenue Requirement to Capital Placed into Service plus COR		5.44%			

Line Notes:

68 Section 5 Attachment 1, Page 18, Line 33, Col (a)
69 Section 5 Attachment 1, Page 27, Line 52, Col (k)
70 Line 68 + Line 69
71 Section 2, Chart 18
72 Line 70 ÷ Line 71

PUC 1-17

Request:

Please expand the table on Bates 97 which includes an itemization of the FY 2022 non infrastructure spending of $1.310 million. The expansion should include:

a. Location of work
b. Risk assessment score
c. FY 2022 revenue requirement associated with the capital expenditure.

Response:

Please see Attachment PUC 1-17 for a table itemizing the total FY 2022 non-infrastructure spending of $1.310 million by project, location, risk score and FY 2022 revenue requirement. The Company has employed the same methodology described in response to Data Request PUC 1-2 to calculate the FY 2022 the revenue requirement by line item as shown in Column (g) of the Attachment.

	Spending Rationale	Project #	Project Description	Location	Risk Assessment Score	FY 2022 Plan Spend	Target Placed In-Service FY22 Including COR	FY 2022 Revenue Requirement
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)=(g)* Line 12
1	Non-Infrastructure	C05360E	CAP OH 5360 RIE1000	-	-	$0	$10,481	$570
2	Non-Infrastructure	COS0006	OCEAN ST-DIST-GENL EQUIP BLANKET	As needed	49	$250,000	$231,797	$12,610
3	Non-Infrastructure	C040644	TELECOM SMALL CAPITAL WORK - RI	As needed	49	$259,600	$276,519	$15,043
4	Non-Infrastructure	C086205	RI ELEC. BARN RIGHT SIZING PROJ.	-	-	$0	$4,334	$236
5	Non-Infrastructure	C086260	PROV. Yard- New Pole Storage Racks	-	-	$0	$105,533	$5,741
6	Non-Infrastructure	C086391	Verizon Copper to Fiber Conversions	Pending Notification	44	$800,000	$496,000	$26,982
7	Total Non-Infrastructure					$1,309,600	$1,124,664	$61,182

8	FY22 Depreciation, Return and Taxes associated with FY22 investment	$3,644,310
9	FY22 Property tax associated with FY22 investment	$2,566,000
10	Total FY22 revenue requirement associated with FY22 investment	$6,210,310
11	Total FY22 Capital Placed into Service plus Cost of Removal (COR)	$114,112,000
12	Ratio of Revenue Requirement to Capital Placed into Service plus COR	5.44%

Line Notes:

68 Section 5 Attachment 1, Page 18, Line 33, Col (a)
69 Section 5 Attachment 1, Page 27, Line 52, Col (k)
70 Line 8 + Line 9
71 Section 2, Chart 18
72 Line 10 ÷ Line 11

PUC 1-18

Request:

Please expand the table on Bates 98 which includes an itemization of the FY 2022 system capacity and performance spending of $18.372 million. The expansion should include:

a. Risk assessment score
b. FY 2022 revenue requirement associated with the capital expenditure.

Response:

Please see Attachment PUC 1-18-1 for a table itemizing the total FY 2022 system capacity and performance spending of $18.372 million by project, risk score and FY 2022 revenue requirement. The Company has employed the same methodology described in response to Data Request PUC 1-2 to calculate the FY 2022 the revenue requirement by line item as shown in Column (g) of the Attachment.

	Spending Rationale	Project #	Project Description	Project Risk Score	FY 2022 Plan Spend	FY 2022 Target Placed In-Service Including COR	FY 2022 Revenue Requirement
	(a)	(b)	(c)	(d)	(e)	(f)	(g)=(f) * Line 48
1	System Capacity & Performance	C028628	Newport SubTrans & Dist Conversion	41	$5,040,000	$5,907,246	$321,354
2	System Capacity & Performance	C046726	East Providence Substation (D-Sub)	41	$407,000	$0	$0
3	System Capacity & Performance	C046727	East Providence Substation (D-Line)	41	$325,000	$65,027	$3,537
4	System Capacity & Performance	C054054	Jepson Substation (D-Line)	41	$24,000	$126,974	$6,907
5	System Capacity & Performance	C058310	Harrison Sub Improvements (D-Sub)	41	$205,000	$0	$0
6	System Capacity & Performance	C058401	Merton Sub Improvements (D-Sub)	41	$190,000	$0	$0
7	System Capacity & Performance	C058404	Kingston Sub Improvements (D-Sub)	41	$325,000	$0	$0
8	System Capacity & Performance	C065166	Warren Sub Expansion (D-Sub)	41	$100,000	$0	$0
9	System Capacity & Performance	C065187	Warren Sub Expansion (D-Line)	41	$521,000	$53,389	$2,904
10	System Capacity & Performance	CD00656	Jepson Substation (D-Sub)	49	$650,000	$667,126	$36,292
11	System Capacity & Performance	C081675	New Lafayette 115/12kV (D-Sub)	35	$1,627,000	$2,300,000	$125,120
12	System Capacity & Performance	C081683	New Lafayette 115/12kV (D-Line)	39	$230,000	$0	$0
13	System Capacity & Performance	COS0016	Ocean St-Dist-Load Relief Blanket.	49	$335,000	$328,466	$17,869
14	System Capacity & Performance	C005505	IE - OS Dist Transformer Upgrades	40	$700,000	$796,526	$43,331
15	System Capacity & Performance	C013967	PS&I Activity - Rhode Island	40	$100,000	$129,490	$7,044
16	System Capacity & Performance	C054090	"Reconductor Anthony Road, Foster R	31	$58,511	$43,749	$2,380
17	System Capacity & Performance	C059663	Cutout Mnted Recloser Program_RI	34	$133,000	$156,885	$8,535
18	System Capacity & Performance	C059882	Flood Contingency Plan NECO - D	41	$44,626	$258,683	$14,072
19	System Capacity & Performance	C074427	EMS Expansion - Phillipsdale 20	25	$86,685	$47,342	$2,575
20	System Capacity & Performance	C074428	EMS Expansion - Wampanoag 48	35	$109,000	$102,229	$5,561
21	System Capacity & Performance	C074430	EMS Expansion - Wood River 85	40	$300,733	$167,641	$9,120
22	System Capacity & Performance	C074431	EMS Expansion - Bonnet 42	25	$99,000	$56,381	$3,067
23	System Capacity & Performance	C074433	Bristol 51 - EMS and breaker rplmt	25	$603,614	$432,059	$23,504
24	System Capacity & Performance	C074438	EMS Expansion - Merton 51	40	$103,540	$63,010	$3,428
25	System Capacity & Performance	C075546	Farnum 105 EMS intallation	39	($2,000)	($1,173)	($64)
26	System Capacity & Performance	C079494	Peacedale 3V0 D-Sub	14	$400,000	$227,554	$12,379
27	System Capacity & Performance	C080894	RI VVO Exp - Farnum Pike 123 Dist	21	$936,000	$561,811	$30,563
28	System Capacity & Performance	C080897	RI VVO Exp - Pontiac 27 Dist	21	$694,626	$420,321	$22,865
29	System Capacity & Performance	C080898	RI VVO Exp - Farnum Pike 23 Dist	21	$400,000	$224,000	$12,186
30	System Capacity & Performance	C080901	RI VVO Exp - Pontiac 27 Sub	21	$575,000	$322,500	$17,544
31	System Capacity & Performance	C084731	RI VVO Expansion - Woonsocket 26	21	$15,000	$104,513	$5,686
32	System Capacity & Performance	C085038	CHOPMIST 3V0 D-SUB	14	$81,000	$183,966	$10,008
33	System Capacity & Performance	C085276	PUTNAM PIKE 3V0 D-SUB	14	$43,000	$39,391	$2,143
34	System Capacity & Performance	C08TBD1	Natick 3V0 D-SUB	14	$500,000	$280,000	$15,232
35	System Capacity & Performance	C08TBD2	WAMPANOAG 3V0 D-SUB	14	$80,000	$45,000	$2,448
36	System Capacity & Performance	C08TBD3	Highland Park 3V0 D-SUB	14	$80,000	$45,000	$2,448
37	System Capacity & Performance	C085540	ELDRED 3V0 D-SUB	14	$125,000	$296,750	$16,143
38	System Capacity & Performance	C085628	RI Mobile 3V0 Units	14	$125,000	$339,608	$18,475
39	System Capacity & Performance	C085688	RI- VVO Putnam Pike	21	$562,000	$345,862	$18,815
40	System Capacity & Performance	C085689	RI VVO Putnam Pike	21	$45,000	$30,545	$1,662
41	System Capacity & Performance	COS0015	Ocean St-Dist-Reliability Blanket.	34	$1,262,000	$1,424,196	$77,476
42	System Capacity & Performance	COS0025	OS-Dist-Substation LR/Rel Blnkt	34	$133,000	$128,466	$6,989
43	Total System Capacity & Performance				$18,372,335	$16,720,533	$909,597

44	FY22 Depreciation, Return and Taxes associated with FY22 investment	$3,644,310
45	FY22 Property tax associated with FY22 investment	$2,566,000
46	Total FY22 revenue requirement associated with FY22 investment	$6,210,310
47	Total FY22 Capital Placed into Service Plus Cost of Removal (COR)	$114,112,000
48	Ratio of Revenue Requirement to Capital Placed into Service Plus COR	5.44%

Line Notes:

44 Section 5 Attachment 1, Page 18, Line 33, Col (a)
45 Section 5 Attachment 1, Page 27, Line 52, Col (k)
46 Line 44 + Line 45
47 Section 2, Chart 18
48 Line 46 ÷ Line 47

PUC 1-19

Request:

The goal of the question is to understand the timing of each of the new Lafayette substation and Wickford substation that will be located within the same fence area. Please provide two timelines on the same page showing the study dates, results, planning, design, engineering, projected in-service date, etc. of (1) the new Lafayette substation and (2) the Wickford substation. Please explain why the projects were not considered as one comprehensive project.

Response:

As shown by the project schedules below, the new Lafayette substation project, which is a Company-driven project, is still in the preliminary engineering phase, while the Wickford Junction project is on a different timeline and is approaching construction start. The Wickford Junction project is a customer-driven project that is being exclusively constructed to address impacts to the system resulting from interconnection of proposed DG projects. These types of projects are engineered to best meet the customer's desired schedule.

In addition, the Company cannot know with certainty that any specific customer driven project will progress. Customers can withdraw their application at any point in time, even after an executed Interconnection Service Agreement (ISA) has been signed. Unless a customer driven project has met satisfactory criteria (specifically, the Company is fully assured the customer-driven project will be constructed and put in service and/or risks associated with the customer driven project not moving forward are minimal), the Company cannot recommend projects determined through area studies that depend on a specific customer project moving forward as that adds risk of meeting the area study project schedule and likely requiring additional cost to ratepayers. Also, all Company-driven projects must proceed through the annual Infrastructure, Safety, and Reliability (ISR) plan process before progressing the project. If a Company-driven project is combined with a customer-driven project, both projects would need to wait for ISR approval before progressing, which could adversely impact the customer schedule. Though the new Lafayette and Wickford Junction projects are separate, the Company has considered both projects as each one progresses. The Company has and continues to work to optimize the design of both projects as best as possible.

Prepared by or under the supervision of: Caitlin Broderick

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Schedules for the new Lafayette and Wickford Junction substations are included below.

	New Lafayette	**Wickford Junction**
Study	South County Area Study	System Impact Study
System Impact Study (Initial) Start	-	February-18
System Impact Study (Initial) Completion	-	June-18
System Impact Study (Final) Start	-	October-19
System Impact Study (Final) Completion	-	July-20
Study Completion Dates	March-18	July-20
Preliminary Engineering start	May-20	September-18
Preliminary Engineering Completion	April-21	December-19
Final Design Completed	September-22	June-21
Construction Start	February-23	November-20
Projected In-Service Date	May-24	December-21

As discussed in the meeting on December 21, 2020, the Company agreed to provide additional information about the progress for the proposed new Lafayette substation and the Wickford Junction substation and the rationale as to designing them as electrically separate substations.

The Company reviewed whether the new Lafayette substation could be supplied by the Wickford Junction 34.5kV yard. This option is not recommended considering the following:

1. There are no reliability benefits or cost benefits of supplying the 12.47kV substation from the 34.5kV Wickford Junction substation as an interruption in the supply to the 34.5 kV source would interrupt all the customers fed from that source (the 12.47 kV customers). This configuration would have inferior reliability for customers.

2. The configuration would result in substantially higher losses on the system resulting in potentially higher costs for other customers. This option would have losses associated with the Wickford Junction 115-34.5kV transformer and the 34.5-12.47kV transformer. If the station is 115-12.47kV, there are only losses associated with one transformer instead of two. This option would also minimize available hosting capacity on the 12.47kV system.

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PUC 1-19, page 3

3. When siting distribution substations, one aspect that is considered is the availability of a transmission supply source (69 kV or above) nearby. With a 115 kV supply available close to the new Lafayette substation, the optimal solution would be to use 115 kV as the supply source.

Supplying the new Lafayette substation and Wickford Junction substation from the same transmission line taps and ring bus would need to be investigated further to confirm feasibility, as there are physical site constraints (possibly requiring land acquisition), new permits (modifying/adding to existing granted permits), that could limit options and feasibility. Even if this configuration was determined feasible, the need for the ring bus is prompted solely due to having 20MWs or more of proposed generation connected at the substation. In order to supply the new Lafayette substation from the needed new ring bus, additional infrastructure would be required, and it is estimated costs assigned to the developer would either remain effectively the same or could potentially increase. In addition, the incremental equipment required with a revised design of the new Lafayette substation would be considerably higher than the current recommended plan.

The Company does not recommend the more costly option for Company-driven projects when both alternatives achieve the same solution as it is the Company's responsibility to recommend the least cost, fit for purpose option for our customers. Therefore, even if supplying the new Lafayette substation from the same 115 kV bus as Wickford Junction was determined feasible, it is not the preferred option for the new Lafayette substation and would have virtually no cost benefits.

Both the new Lafayette substation and Wickford Junction substation are fully optimized based upon their current electrical arrangement and there is very limited space for any additions. The current design is the best option for both projects and the Company will continue to optimize the projects wherever possible as they progress. For example, a separate control enclosure for new Lafayette substation is not being installed; instead one control enclosure will serve both the Wickford Junction and new Lafayette substations.

Wickford Junction is being executed under an EPC (Engineer, Procure, Construct) contract. Any changes to the current designs will result in significant schedule delays, contract change orders and potentially additional costs to the developer. Redesigning these projects could result in a delay of approximately 12-18 months. This could potentially be delayed further due to ISO-NE restudy requirements and any required permit re-filings.

Prepared by or under the supervision of:

PUC 1-20

Request:

Please explain why the Wickford substation was not an option for addressing the asset conditions issues identified in the South County Area Study. Was the Division provided, as part of the ISR, information on the interconnection study that would result in the Wickford substation when it was reviewing the proposed new Lafayette substation? If not, why not? If so, please provide the documentation.

Response:

The Wickford substation project does not address existing area needs as identified by the Company through its area study. The Wickford substation project exclusively addresses system impacts specifically created by the addition of proposed large-scale solar interconnections in the area.

The Wickford substation project is a customer-driven project, and these types of projects are engineered to best meet the customer's desired schedule. The Company cannot know with certainty that any specific customer-driven project will progress to completion. Customers may withdraw their application at any point in time, even after an executed Interconnection Service Agreement (ISA) has been signed. Unless a customer-driven project has met satisfactory criteria (specifically, the Company is fully assured the customer-driven project will be constructed and placed in service and/or risks associated with the customer-driven project not moving forward are minimal), the Company cannot recommend projects determined through area studies that depend on a specific customer project moving forward, as that adds risk of meeting the area study project schedule and likely requiring additional cost to ratepayers. Therefore, the Company did not look to solve area study issues with a proposed distributed generation customer project.

The Division was not provided the interconnection study since interconnection studies are not part of annual ISR plans.

PUC 1-21

Request:

Please explain whether the Company revisited the results of the South County Area Study in light of construction of the Wickford Junction substation with an expected in-service date of December 2021 between July 2018 and May 2020. If not, why not? If so, what were the results of the review?

Response:

The Company did not revisit the results of the South County East Area study in light of the construction of the Wickford Junction substation with an expected in-service date of December 2021. As explained in PUC 1-19 and 1-20, the Wickford Junction and new Lafayette projects have different drivers and address different issues.

The Wickford Junction substation built for a Distributed Generation (DG) customer does not address the loading, asset condition or reliability issues identified in the South County East Study. The South County East area study did not need to be revisited since the recommendations in the study remain the same regardless of the installation of the Wickford Junction substation.

The issues identified in the South County East area study require a new substation with a low side of 12.47kV to supply the existing 12.47kV distribution system and enable retirement of other higher voltage circuits that supply the existing Lafayette substation. The Company continues to evaluate ways to combine the two projects from a construction implementation perspective to maximize efficiencies.

Prepared by or under the supervision of: Caitlin Broderick

PUC 1-22

Request:

When was the Division first advised that the Wickford Junction substation and New Lafayette substation would be in the same fence area?

Response:

The Division was first advised that the Wickford Junction substation and new Lafayette substation would be in the same fence area in a meeting between the Division and the Company on August 18, 2020.