Andrew S. Marcaccio
Senior Counsel

March 11, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 5234 – 2022 Annual Retail Rate Filing
Responses to PUC Data Requests – Set 1 (Complete Set)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed please find the Company's complete set of responses to the First Set Data Requests issued by the Public Utilities Commission ("PUC") in the above-referenced docket.[1]

In addition to the responses submitted on March 4, 2022, this transmittal includes PUC 1-12, PUC 1-13; and PUC 1-19 through PUC 1-23.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5234 Service List
John Bell, Division
Al Mancini, Division
Tiffany Parenteau, Esq.
Greg Schultz, Esq.

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[1] Per a communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

280 Melrose Street, Providence, RI 02907
T: 401.784.4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

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.

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Joanne M. Scanlon

March 11, 2022
Date

National Grid – 2022 Annual Retail Rate Filing - Docket No. 5234
Service List Updated 2/23/2022

Name/Address	E-mail Distribution	Phone
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PPL Electric Utilities Ronald Reybitz Stephen Breininger	rjreybitz@pplweb.com; skbreininger@pplweb.com;	
Green Development Matt Sullivan	ms@green-ri.com;	

PUC 1-1

Request:

Referencing page 2 of Schedule NECO-2, please explain why the Company's LRS collections for residential customers in September 2021 varied more from actual LRS expenses ($6.145 million over-collection) than in any other month. In your response, please explain the causes for the September over-collection.

Response:

Schedule NECO-2, Page 2 reflects revenues in Column (b) on a billing month basis based on cycle billing, not on a calendar month basis based on a calendar month's usage. The month of January 2021 represents a partial month of revenue that only reflects revenue associated with kWh delivered and billed in the month of January 2021 and does not reflect the kWh delivered in January and billed in the month of February. The month of February 2021 contains revenue associated with kWh delivered in January as well as kWh delivered in February. Each month of revenue presented in the schedule contains revenue associated with the previous month and the current month. The expense in Column (c) represents calendar month expense. As a result, the monthly over/(under) presented in Column (d) is comparing revenue for a billing month to costs incurred on a calendar month basis.

In order to compare calendar month revenues to calendar month expenses, the Company has revised page 2 of Schedule NECO-2 in Attachment PUC 1-1. This attachment presents the same Residential reconciliation as presented in Schedule NECO-2, Page 2 but with revenues presented in Column (b) based on an estimated calendar month basis. As a result of presenting calendar month revenue, the monthly over/(under) recovery for September 2021 is an over-recovery of $2.6 million and is no longer the highest monthly variance. The over-recovery of $5.2 million in the month of October is now the highest variance of all the months.

The over-recovery of $5.2 million for October 2021 is primarily caused by two factors: rate design and the procurement of capacity costs. The Company bills residential customers for Last Resort Service fixed rates which are based on a weighting of monthly prices at which the Company has procured power on behalf of its customers via the most recently approved Last Resort Service Procurement Plan. In some months the fixed rate is higher than the underlying cost and in other months it is lower than the underlying cost. For the month of October 2021, the fixed base LRS rate of $0.10491 per kWh was greater than the underlying monthly variable cost of $0.08491 per kWh used in the calculation of the fixed rate, thus driving an over-recovery for

October 2021. Multiplying this $0.02 per kWh differential by the estimated Residential Last Resort Service kWh delivered in October 2021 of 196,598,033 kWh results in an over-recovery of approximately $3.9 million. Second, since April 2019, the Company has used estimated capacity prices to develop rates for all three customer groups. The extent to which actual capacity clearing prices differ from the estimates will contribute to an over or under-recovery. As presented on page 7 of Schedule NECO-2, the Company estimates that the actual capacity clearing prices being higher than estimates resulted in an over recovery of $1.2 million for the month of October.

Prepared by or under the supervision of:
Daniel Gallagher, Stephanie Briggs and Jeffrey Oliveira

The Narragansett Electric Company
LAST RESORT SERVICE RECONCILIATION
For the Period January 1, 2021 through December 31, 2021
Base Reconciliation - By Customer Group

Residential

		Beginning Balance (a)	Calendar Month Revenue (b)	Expense (c)	Monthly Over/(Under) (d)	Ending Balance (e)
(1)	Jan-21	$0	$23,902,093	$27,927,144	($4,025,051)	($4,025,051)
(2)	Feb-21	($4,025,051)	$21,946,104	$25,351,049	($3,404,945)	($7,429,997)
(3)	Mar-21	($7,429,997)	$20,175,116	$19,238,128	$936,988	($6,493,009)
(4)	Apr-21	($6,493,009)	$13,367,898	$15,086,209	($1,718,311)	($8,211,320)
(5)	May-21	($8,211,320)	$14,618,503	$14,803,096	($184,593)	($8,395,913)
(6)	Jun-21	($8,395,913)	$18,302,092	$16,826,824	$1,475,268	($6,920,645)
(7)	Jul-21	($6,920,645)	$22,160,703	$20,600,588	$1,560,115	($5,360,530)
(8)	Aug-21	($5,360,530)	$23,057,579	$20,948,062	$2,109,517	($3,251,013)
(9)	Sep-21	($3,251,013)	$18,345,245	$15,759,781	$2,585,464	($665,549)
(10)	Oct-21	($665,549)	$20,193,955	$15,017,357	$5,176,598	$4,511,049
(11)	Nov-21	$4,511,049	$21,259,633	$17,532,317	$3,727,316	$8,238,365
(12)	Dec-21	$8,238,365	$24,710,486	$22,984,551	$1,725,935	$9,964,300
(13)	Jan-22					$9,964,300
(14)	Remaining Balance from Over/(Under) Recovery incurred during 2019					($719,675)
(15)	Total Net Unbilled LRS Billing Adjustments					($7,439)
(16)	Total Adjustments					($727,114)
(17)	Ending Balance Prior to Application of Interest					$9,237,186
(18)	Interest					$50,728
(19)	Ending Balance Including Interest					$9,287,914

(1)
(13)
(14) Final Balance of Page 8, Column (g), Section 1
(15) Schedule NECO-8, Column (a), Line (13)
(16) Line (14) + Line (15)
(17) Ending balance, Column (e) + Line (16)
(18) [(Beginning balance + Ending balance) ÷ 2] x [(2.14% x 2/12) + (0.89% x 10/12)]
(19) Line (17) + Line (18)

(a) Column (e) from previous row
(b) Page 5, Column (a) - Residential
(c) Page 6, Column (e) - Residential
(d) Column (b) - Column (c)
(e) Column (a) + Column (d)

PUC 1-2

Request:

Referencing page 7 of Schedule NECO-2, please explain why actual capacity rates ($/MWh) were higher than estimated rates in all but one month of 2021 for residential LRS customers, but lower than estimated rates in every month of 2021 for commercial LRS customers?

Response:

The Company's Estimated Capacity LRS Rates ($/MWH) in column (e) are calculated at the time of each Last Resort Service (LRS) rate filing. The Company estimates the capacity settlement for each customer group for each month by estimating the various inputs in the ISO-NE capacity settlement calculation. The Company unitizes the estimated fixed capacity charges into a volumetric ($/MWh) rate by dividing the capacity settlement for each customer group for each month by each group's wholesale monthly load forecast. This capacity rate is added to the $/MWh LRS bid rate (and an estimate of spot market if applicable), which is then adjusted by a line loss factor to create the LRS Base Rate for a month.

Actual Capacity Settlement Rates ($/MWh) in column (f) are the actual capacity settlement amounts for each customer group for each month divided by each group's actual wholesale monthly load. The specific causes of the deviations in each month can be attributed to the differences in estimated and actual loads as well as differences in estimated capacity settlement and actual capacity settlement. The impact of these two sources of deviations for each month and each customer group is shown in the following table:

PUC 1-2, page 2

Percentage Differences (Estimate to Actual)

	Residential			Commercial			Industrial		
	Capacity Settlement	Load	$ / MWh	Capacity Settlement	Load	$ / MWh	Capacity Settlement	Load	$ / MWh
Jan-21	3%	17%	-12%	4%	-10%	15%	12%	-2%	14%
Feb-21	3%	14%	-9%	3%	-5%	9%	12%	0%	12%
Mar-21	3%	-1%	5%	3%	-8%	12%	8%	-13%	25%
Apr-21	3%	1%	2%	3%	-4%	7%	2%	14%	-11%
May-21	2%	6%	-4%	2%	-4%	6%	-1%	8%	-9%
Jun-21	-3%	32%	-27%	23%	8%	14%	-4%	15%	-16%
Jul-21	-3%	5%	-7%	23%	-8%	34%	3%	7%	-3%
Aug-21	-3%	27%	-23%	23%	-1%	24%	4%	7%	-3%
Sep-21	-3%	28%	-24%	24%	2%	22%	11%	31%	-15%
Oct-21	5%	21%	-14%	6%	-1%	7%	20%	37%	-13%
Nov-21	5%	12%	-6%	7%	3%	4%	24%	46%	-15%
Dec-21	4%	4%	0%	7%	4%	3%	27%	61%	-21%
2021	1%	14%	-11%	9%	-2%	12%	9%	16%	-6%

For example, in January 2021 the Actual Capacity Settlement Rate ($/MWh) is 12% lower than the Estimated Capacity LRS Rate ($/MWh) for the Residential Group. The actual capacity settlement amount was only 3% higher than the estimate, but the actual load was 17% higher than the estimate. When unitizing a fixed capacity charges into a volumetric ($/MWh) rate, actual load that is higher than estimated load will result in a lower actual $/MWh rate which explains the actual rate in January 2021 of $29.40/MWh compared to the estimated rate of $33.31/MWh on page 7 of Schedule NECO-2.

The 2021 row compares the estimated and actual capacity settlement, loads, and $/MWh rate for the entire year. For the Residential Group, it indicates that the higher actual loads are the primary driver of the lower $/MWh capacity rate. For the Commercial Group, it indicates that the higher actual capacity settlement is the primary driver of the higher $/MWh capacity rate. Finally, for the Industrial Group, the higher actual loads had a larger impact than the higher actual capacity settlement, resulting in a lower Actual Capacity Settlement ($/MWh) compared to the estimate.

PUC 1-3

Request:

When developing the forecast LRS kWhs included on page 2 of Schedule NECO-3, did the Company consider the potential impact to LRS deliveries of any municipal aggregations that may launch in 2022? Why or why not? If so, how did the Company account for those potential impacts?

Response:

No, the Company did not consider the potential impact of municipal aggregations on the forecasted LRS forecast on page 2 of Schedule NECO-3.

Although the PUC has approved municipal aggregations, it is unclear to the Company when they will be implemented and when customers will be enrolled and begin receiving service through the municipal aggregation(s). Also, since these programs operate as opt-out programs, the Company is unable to estimate how many customers, if any, would opt-out of the municipal aggregations and remain or return to LRS. Therefore, due to this uncertainty, the Company did not consider the potential impact to LRS deliveries of any municipal aggregations that may launch in 2022 on the forecasted kWh included in Schedule NECO-3, Page 2.

Prepared by or under the supervision of:
Daniel Gallagher, Stephanie Briggs, and Jeffrey Oliveira

PUC 1-4

Request:

Why does the Company base its LRS deliveries forecast on the ratio of LRS deliveries to total deliveries in the month of January? What is the significance of using January data, compared to other months?

Response:

The Company based its LRS deliveries forecast on the ratio of LRS deliveries to total deliveries in the month of January 2022 as it was the most recently available billing data at the time of preparing the filing to reflect the level of monthly kWh deliveries associated with LRS and Competitive Supply. Please refer to the Company's response to PUC 1-5 for the monthly ratio of LRS deliveries to total deliveries for calendar year 2021. The ratio of LRS deliveries in the month of January 2022 are comparable to the ratios during calendar year 2021.

Prepared by or under the supervision of:
Daniel Gallagher, Stephanie Briggs and Jeffrey Oliveira

PUC 1-5

Request:

Referencing lines 14 – 16 of page 2 of Schedule NECO-3, please provide similar numbers for each LRS group for all 12 months of 2021 (January– December).

Response:

Please see the tables below for the requested information.

	Residential kWh Deliveries		
	Last Resort Service	**Total kWh**	**% of Total**
Jan-21	263,312,175	289,930,449	90.8%
Feb-21	248,028,224	272,865,133	90.9%
Mar-21	224,752,812	246,033,617	91.4%
Apr-21	197,683,213	216,978,730	91.1%
May-21	174,856,565	191,647,143	91.2%
Jun-21	228,129,837	249,867,617	91.3%
Jul-21	279,459,596	306,055,148	91.3%
Aug-21	317,450,918	345,787,767	91.8%
Sep-21	302,609,173	329,184,074	91.9%
Oct-21	210,913,779	229,276,822	92.0%
Nov-21	175,203,313	190,379,430	92.0%
Dec-21	223,114,200	241,544,852	92.4%

	Commercial kWh Deliveries		
	Last Resort Service	**Total kWh**	**% of Total**
Jan-21	81,218,019	160,720,243	50.5%
Feb-21	83,979,805	165,187,161	50.8%
Mar-21	82,087,624	163,755,186	50.1%
Apr-21	77,223,904	151,551,453	51.0%
May-21	73,874,615	142,024,162	52.0%
Jun-21	83,606,806	165,411,307	50.5%
Jul-21	89,187,595	176,662,538	50.5%
Aug-21	94,376,908	183,926,142	51.3%
Sep-21	96,216,703	185,253,298	51.9%
Oct-21	79,665,898	155,180,057	51.3%
Nov-21	71,406,470	143,368,527	49.8%
Dec-21	79,968,653	154,258,235	51.8%

Prepared by or under the supervision of:
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PUC 1-5, page 2

	Industrial kWh Deliveries		
	Last Resort Service	**Total kWh**	**% of Total**
Jan-21	16,621,910	184,994,889	9.0%
Feb-21	16,525,011	183,778,496	9.0%
Mar-21	19,828,257	187,496,325	10.6%
Apr-21	18,464,953	177,975,007	10.4%
May-21	14,274,597	162,438,477	8.8%
Jun-21	15,607,562	187,974,907	8.3%
Jul-21	18,681,745	214,666,769	8.7%
Aug-21	18,577,564	208,083,474	8.9%
Sep-21	18,738,589	207,641,913	9.0%
Oct-21	18,981,233	190,703,828	10.0%
Nov-21	15,619,510	175,114,176	8.9%
Dec-21	16,691,945	186,970,724	8.9%

Prepared by or under the supervision of:
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PUC 1-6

Request:

Please provide a table containing the following columns of data for the periods of April – March in years 2017, 2018, 2019, 2020, and 2021:

a. Forecast residential LRS deliveries
b. Actual residential LRS deliveries
c. Forecast commercial LRS deliveries
d. Actual commercial LRS deliveries
e. Forecast industrial LRS deliveries
f. Actual industrial LRS deliveries

Response:

Please see Attachment PUC 1-6 for the requested information.

Residential		
	Forecasted	Actual
Date	LRS kWh	LRS kWh
	(a)	(b)
Apr-17	191,706,955	200,605,777
May-17	170,084,980	171,712,684
Jun-17	196,786,440	196,243,091
Jul-17	254,773,736	269,821,066
Aug-17	294,437,355	276,027,598
Sep-17	249,160,834	235,509,846
Oct-17	195,980,032	192,571,244
Nov-17	189,755,112	194,226,201
Dec-17	223,351,325	206,282,151
Jan-18	239,043,398	273,522,306
Feb-18	222,140,210	228,078,117
Mar-18	213,910,202	201,668,558
Total FY2018	2,641,130,580	2,646,268,639
Apr-18	195,700,123	195,077,337
May-18	175,363,046	188,444,942
Jun-18	200,543,199	189,115,621
Jul-18	256,307,761	281,027,227
Aug-18	278,136,739	312,480,240
Sep-18	244,581,728	309,770,827
Oct-18	187,776,270	198,052,046
Nov-18	178,447,575	187,299,247
Dec-18	216,624,829	219,707,833
Jan-19	245,218,357	245,925,850
Feb-19	226,853,782	231,451,728
Mar-19	213,221,541	212,498,391
Total FY2019	2,618,774,950	2,770,851,289
Apr-19	187,211,588	177,781,141
May-19	179,439,583	179,552,012
Jun-19	188,741,347	185,038,981
Jul-19	257,918,209	260,488,730
Aug-19	283,638,859	331,188,704
Sep-19	237,154,852	252,301,528
Oct-19	174,107,091	179,369,907
Nov-19	172,572,325	170,655,588
Dec-19	214,709,808	212,101,761
Jan-20	245,752,938	254,753,315
Feb-20	222,457,950	201,158,802
Mar-20	210,769,681	197,885,727
Total FY2020	2,574,474,231	2,602,276,196
Apr-20	205,973,456	200,762,519
May-20	170,185,706	196,688,960
Jun-20	191,679,390	205,680,375
Jul-20	273,786,617	308,738,265
Aug-20	276,476,071	373,751,032
Sep-20	247,953,227	260,915,561
Oct-20	181,219,789	201,454,925
Nov-20	179,552,090	193,385,615
Dec-20	218,603,831	220,482,294
Jan-21	249,321,934	263,312,175
Feb-21	227,648,420	248,028,224
Mar-21	212,574,194	224,752,812
Total FY2021	2,634,974,725	2,897,952,757
Apr-21	219,312,681	197,683,213
May-21	172,348,574	174,856,565
Jun-21	200,928,500	228,129,837
Jul-21	278,774,758	279,459,596
Aug-21	297,990,236	317,450,918
Sep-21	260,559,980	302,609,173
Oct-21	184,017,837	210,913,779
Nov-21	180,749,703	175,203,313
Dec-21	224,895,829	223,114,200
Jan-22	247,382,378	250,406,587
Feb-22	230,890,283	256,776,226
Mar-22	223,278,823	-
Total FY2022 to date*	2,497,850,759	2,616,603,407

*Does not include March 2022

Commercial		
	Forecasted	Actual
Date	LRS kWh	LRS kWh
	(c)	(d)
Apr-17	75,403,198	77,645,223
May-17	71,618,421	72,912,514
Jun-17	79,097,149	82,528,412
Jul-17	88,733,285	92,930,747
Aug-17	93,322,409	93,500,861
Sep-17	89,490,028	89,186,814
Oct-17	77,812,121	79,196,846
Nov-17	74,377,018	76,746,841
Dec-17	81,867,642	76,058,743
Jan-18	81,751,196	92,328,135
Feb-18	79,148,656	83,375,519
Mar-18	79,969,109	79,487,844
Total FY2018	972,590,232	995,898,499
Apr-18	75,372,384	78,612,733
May-18	72,533,352	79,264,084
Jun-18	78,440,086	82,886,041
Jul-18	86,185,753	97,598,272
Aug-18	89,354,171	103,514,064
Sep-18	85,888,791	105,516,234
Oct-18	79,458,224	82,767,885
Nov-18	74,108,693	75,475,898
Dec-18	79,528,209	85,379,923
Jan-19	82,965,916	89,963,548
Feb-19	78,081,452	86,891,721
Mar-19	75,491,973	87,617,343
Total FY2019	957,409,005	1,055,487,746
Apr-19	80,565,282	81,157,907
May-19	80,463,465	76,655,424
Jun-19	82,824,560	83,061,359
Jul-19	93,969,515	94,604,911
Aug-19	98,614,651	109,051,887
Sep-19	91,342,920	93,737,502
Oct-19	82,181,870	79,043,335
Nov-19	78,668,661	71,026,992
Dec-19	85,241,471	84,638,534
Jan-20	88,495,117	95,717,350
Feb-20	82,406,727	81,527,184
Mar-20	80,950,198	83,406,622
Total FY2020	1,025,724,437	1,033,629,007
Apr-20	80,436,589	74,522,425
May-20	74,748,906	68,383,386
Jun-20	77,523,501	71,336,009
Jul-20	92,993,625	85,798,558
Aug-20	91,063,920	99,341,926
Sep-20	87,931,335	83,496,878
Oct-20	82,988,444	79,946,625
Nov-20	80,016,854	66,523,151
Dec-20	85,135,571	77,251,192
Jan-21	88,466,120	81,218,019
Feb-21	82,593,461	83,979,805
Mar-21	78,046,093	82,087,624
Total FY2021	1,001,944,419	953,885,598
Apr-21	79,231,148	77,223,904
May-21	71,674,358	73,874,615
Jun-21	77,333,910	83,606,806
Jul-21	89,818,884	89,187,595
Aug-21	92,082,386	94,376,908
Sep-21	86,586,291	96,216,703
Oct-21	77,267,759	79,665,898
Nov-21	72,804,843	71,406,470
Dec-21	77,696,045	79,968,653
Jan-22	79,402,662	82,710,316
Feb-22	75,381,478	92,574,069
Mar-22	75,038,890	-
Total FY2022 to date*	879,279,764	920,811,937

*Does not include March 2022

Industrial		
	Forecasted	Actual
Date	LRS kWh	LRS kWh
	(e)	(f)
Apr-17	19,080,538	18,637,626
May-17	17,999,352	17,439,777
Jun-17	19,627,470	18,436,866
Jul-17	20,025,807	21,422,861
Aug-17	20,888,349	21,868,693
Sep-17	21,002,542	19,903,848
Oct-17	18,638,739	23,220,557
Nov-17	19,079,458	18,919,757
Dec-17	19,760,484	17,659,765
Jan-18	18,517,083	21,915,401
Feb-18	19,459,802	18,720,920
Mar-18	18,863,383	19,045,811
Total FY2018	232,943,007	237,191,882
Apr-18	19,805,791	18,554,467
May-18	19,206,910	17,642,769
Jun-18	20,564,065	19,826,086
Jul-18	22,679,448	22,450,823
Aug-18	23,453,555	22,390,615
Sep-18	22,434,629	28,684,202
Oct-18	20,547,377	24,244,325
Nov-18	19,307,442	22,846,668
Dec-18	20,535,724	25,594,201
Jan-19	21,314,063	23,249,402
Feb-19	20,262,847	21,985,054
Mar-19	19,730,184	18,598,611
Total FY2019	249,842,034	266,067,223
Apr-19	22,217,121	31,122,350
May-19	22,192,964	11,832,395
Jun-19	22,851,347	18,506,130
Jul-19	25,767,866	26,585,390
Aug-19	26,882,468	29,683,018
Sep-19	24,930,212	22,722,962
Oct-19	22,355,340	19,582,764
Nov-19	21,432,134	18,000,061
Dec-19	22,969,107	19,947,872
Jan-20	23,719,450	17,384,970
Feb-20	22,311,071	15,383,431
Mar-20	22,046,573	15,437,649
Total FY2020	279,675,654	246,188,992
Apr-20	35,744,645	19,269,006
May-20	33,874,409	15,376,222
Jun-20	34,964,233	18,427,905
Jul-20	41,190,543	18,936,037
Aug-20	40,453,613	18,330,484
Sep-20	38,933,678	16,799,883
Oct-20	36,794,582	16,116,956
Nov-20	35,383,254	17,285,555
Dec-20	37,149,954	19,652,932
Jan-21	38,114,273	16,621,910
Feb-21	35,955,623	16,525,011
Mar-21	34,391,369	19,828,257
Total FY2021	442,950,176	213,170,158
Apr-21	15,944,725	18,464,953
May-21	14,790,649	14,274,597
Jun-21	15,810,959	15,607,562
Jul-21	18,107,192	18,681,745
Aug-21	18,484,773	18,577,564
Sep-21	17,390,095	18,738,589
Oct-21	15,647,583	18,981,233
Nov-21	14,747,197	15,619,510
Dec-21	15,482,038	16,691,945
Jan-22	15,683,241	17,779,373
Feb-22	15,019,549	17,749,509
Mar-22	15,138,173	-
Total FY2022 to date*	177,108,001	191,166,580

*Does not include March 2022

PUC 1-7

Request:

Regarding the Company's proposed revision to the Non-Bypassable Transition Charge Adjustment Provision, please describe the process by which the Company will notify the Commission that it has redirected any Contract Termination Charge credits to the Storm Fund, including the timing and frequency of such notifications.

Response:

By January 31 of each year, the New England Power Company ("NEP") and the former Montaup Electric Company ("Montaup") distributes its annual report on the reconciliation of Contract Termination Charges ("CTC") to the Company associated with The Narragansett Electric Company ("NECO"), the former Blackstone Valley Electric Company, and the former Newport Electric Company. These reports, which are also filed with the Commission, also contain the upcoming calendar year's CTCs to the Company and are used as the basis for the base Non-Bypassable Transition Charge effective April 1 of that same calendar year. As proposed in the revised tariff, if the CTCs for the upcoming calendar year are a credit, then the respective credit billed to the Company will be reflected in the Storm Fund, which means that there will be no base Non-Bypassable Transition Charge (assuming all three CTCs are credits).

In the Company's Annual Retail Rate Filing ("ARRF") filed with the Commission by February 15 each year, the Company will identify whether it will be proposing a base Non-Bypassable Transition Charge. The Company will provide justification for its proposal, and if the CTCs from NEP and/or Montaup are a credit to the Company (there are three separate CTCs), then the Company will indicate this in the ARRF.

In addition, the Company's annual Storm Fund Report in Docket 2509 filed annually by April 1 would reflect the previous calendar year's amount of CTC credits applied to the Storm Fund.

Prepared by or under the supervision of: Jeffrey Oliveira and Stephanie Briggs

PUC 1-8

Request:

For the period of April 2022 – March 2023, does the Company expect to receive any credits through the annual Contract Termination Charge?

Response:

As indicated in New England Power Company's ("NEP") January 2022 Contract Termination Charge ("CTC") Reconciliation Report to the Company, Schedule 1, Page 1, Line (49), Column (9); Montaup Electric Company's ("Montaup") January 2022 CTC Reconciliation Report to the Company for Blackstone Valley Electric Company, Schedule 1, Page 1, Column (7) for 2022; and Montaup's January 2022 CTC Reconciliation Report to the Company for Newport Electric Company, Schedule 1, Page 1, Column (7) for 2022, all three CTC reconciliation reports indicate a credit would be provided to the Company during calendar 2022. The credits are mostly related to the Hydro Quebec purchase power contracts, where the revenues from the resales on the open market are much higher than the operating expenses. Concurrent with the effective date of the revisions to the Non-bypassable Charge Adjustment Provision, the Company will credit the Storm Contingency Fund the monthly credits it will receive on CTC bills from NEP and the former Montaup for the months April 2022 through December 2022. NEP's and the former Montaup's January 2023 CTC reconciliation report will indicate whether or not a credit would be provided to the Company during calendar 2023.

In addition, on page 23 of the pre-filed direct testimony, the Company has indicated it is not proposing a base Non-bypassable Transition Charge, which is a result of the CTCs (there are three separate CTCs) to be billed to the Company being a credit and thereby will be credited to the Storm Contingency Fund. If any of the CTCs to be billed to the Company were to be a surcharge, the Company would have proposed a base Non-bypassable Transition Charge associated with that CTC with the base Non-bypassable Transition Charge also being a surcharge.

Prepared by or under the supervision of: Jeffrey Oliveira and Stephanie Briggs

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PUC 1-9

Request:

Regarding Regional Network Load, please provide two tables with the following information:

a. Total annual RNL (i.e. sum of 12 monthly RNL values) across all of ISO-NE from the past 5 years.
b. Narragansett Electric's annual RNL (i.e. sum of 12 monthly RNL values) from the past 5 years

Response:

Please see Attachment PUC 1-9 that contains the Total Annual Regional Network Load for Narragansett Electric and total for ISO-NE for the Calendar Years 2017 through 2021.

The Narragansett Electric Company
Narragansett Electric & Total ISO-NE Regional Network Load

Line #	CY Period	(1) Narragansett Annual PTF kW Load	(2) ISO-NE Total Annual PTF kW Load
1	2017	14,781,735	233,236,423
2	2018	14,889,655	234,508,072
3	2019	13,981,327	222,678,268
4	2020	13,386,182	218,924,163
5	2021	14,264,205	226,969,337

Notes
Line 1-5: Column (1) = Narragansett Electric Total Regional Network Load per calendar year
Line 1-5: Column (2) = ISO-NE Total Regional Network Load per calendar year
Line 5: Column (1) & (2) includes initial kW load for the periods of November & December 2021

PUC 1-10

Request:

On Bates page 255, the Company writes "the increase in the forecasted ISO-NE Charges is primarily driven by a 6% increase in the Company's Regional Network Load driving an increase of $9.56 million. RNS rate increased by 5.12%, which is driving an increase of $7.79 million; this results in a $17.35 million increase in the forecasted PTF Demand Charge." Does this suggest that the increase in (forecast) PTF demand charges assessed to Narragansett Electric between 2021 to 2022 is primarily driven by increases in Narragansett Electric's own Regional Network Load, as opposed to increases in underlying system costs (i.e. the RNS rate)?

Response:

Yes. The increase in the forecasted PTF Demand Charge when compared to the prior year's forecast is driven more by the increase in Narragansett Electric's Regional Network Load. For forecasting purposes, the Company utilizes actual prior year load data and a combination of actual RNS rates in effect and forecasted RNS rates. The year over year change in actual charges to Narragansett Electric may be driven by different factors than forecasted.

PUC 1-11

Request:

Referencing page 5 of Schedule NECO-12, please explain how the Company measured and/or derived the 2021 monthly coincident peak data for each rate class. In your response, specifically explain how the Company measured and/or derived coincident peak data for those rate classes without demand or interval meters.

Response:

For the sample Rate Classes without interval meters (A-16/A-60, C-06 and G-02), the Company derived the 2021 monthly coincident peak data for each rate class using Class Average Load Shapes.

The Company constructs its sample Load Shapes based on this methodology:

1) Sample sizes and stratification cut points were developed using Model-Based Statistical Sampling techniques
2) Annual kWh is the basis for stratification
3) Hourly loads are computed using Ratio Estimation
4) Statistical Computer models use electric utility industry standard SAS-based software
5) National Grid completes an annual Load Study, by Rate Class, as part of its Load Research program

Specific customer premises were selected as sample sites for each Rate Class based on "Random Sampling", according to stratum, using customer-specific Annual kWh.

The sample data used is the most representative current available data to date.
For the non-sample Rate, those classes with demand and interval meters, the Company bases the Class Average Load Shapes on these methodologies:

1) For rates B-32, G-32 and X-01, the Company uses census load shapes
2) For SL, the Company uses a load profile which consists of 0's and 1's, corresponding to seasonal patterns in sunrise and sunset. Hours of darkness are assigned a "1" value, and daylight values are assigned a "0" value. This load profile approach is referred to as a "deemed profile" and is considered industry standard for streetlighting.

Prepared by or under the supervision of: Robert Kraus

PUC 1-12

Request:

Please update the response to PUC 2-6 in Docket No. 5127 to provide your best estimate of PTF charges for the period of April 2022-March 2023 if the OATT changes currently being contemplated by FERC (relating to the reconstitution of RNL for behind-the-meter generation) take effect. In your response, provide an updated version of Attachment PUC 2-6, for the period April 2022-March 2023.

Response:

Please see Attachment PUC 1-12 for the updated data in the period of April 2022 - March 2023.

Prepared by or under the supervision of: Vishal Ahirrao

The Narragansett Electric Company
Estimated Changes in PTF Demand Charges
Estimated for the Year 2022 Due to Reconstitution of Regional Network Load

Line #	Period	(1) Annual RNS Rate ($/kW-Yr)	(2) Monthly PTF kW Load	(3) PTF Demand Charge	(4) Reconstituted Load Impact	(5) Revised Monthly PTF kW Load	(6) Revised PTF Demand Charge	(7) Variance PTF Demand Charge
1	April	$142.78	846,825	$10,075,752	28,757	875,582	$10,417,910	$342,159
2	May	$142.78	1,028,841	$12,241,427	26,356	1,055,197	$12,555,018	$313,591
3	June	$142.78	1,617,488	$19,245,307	35,903	1,653,391	$19,672,491	$427,184
4	July	$142.78	1,543,633	$18,366,561	38,972	1,582,605	$18,830,260	$463,699
5	August	$142.78	1,564,102	$18,610,106	44,140	1,608,242	$19,135,296	$525,190
6	September	$142.78	1,232,500	$14,664,616	39,190	1,271,690	$15,130,910	$466,293
7	October	$142.78	973,371	$11,581,430	25,253	998,624	$11,881,897	$300,467
8	November	$142.78	1,168,768	$13,906,316	28,636	1,197,404	$14,247,035	$340,719
9	December	$142.78	1,158,086	$13,779,219	48,844	1,206,930	$14,360,378	$581,159
10	January	$147.09	1,091,298	$13,376,585	28,606	1,119,904	$13,727,223	$350,638
11	February	$147.09	1,008,998	$12,367,793	39,026	1,048,024	$12,846,154	$478,361
12	March	$147.09	1,030,295	$12,628,841	25,511	1,055,806	$12,941,542	$312,701
13	**Total**		**14,264,205**	**$170,843,952**	**409,194**	**14,673,399**	**$175,746,112**	**$4,902,160**

Notes
Line 1-9: Column (1) = Schedule AS-4 Line 1
Line 10-12: Column (1) = Schedule AS-4 Line 8
Line 1-12: Column (2) = ISO-NE Monthly Regional Network Load Reports January 2021 to December 2021 as per Schedule AS-3
Line 1-12: Column (3) = Column (1) x Column (2) / 12
Line 1-12: Column (4) = Internal Records
Line 1-12: Column (5) = Column (2) + Column (4)
Line 1-12: Column (6) = Column (1) x Column (5) / 12
Line 1-12: Column (7) = Column (6) - Column (3)

PUC 1-13

Request:

Please update the response to PUC 4-1 in Docket No. 5127 (including the response table) for all distributed generation facilities in Rhode Island that participate in National Grid's renewable energy programs and are registered with ISO-NE as generation assets (including as Settlement Only Generators) interconnected as of December 31, 2021.

Response:

Please see the table below:

Asset ID	(a) Nameplate Capacity (MW)	(b) Asset Registration Capacity (MW)	(c) Does Renewable Energy Program	(d) Will Facility Reduce National Grid's RNL (Yes/No)	(e) Facility will or will not reduce National Grid's Regional Network Load (RNL) under the Transmission Owners' prosed change to the definition of RNL in the ISO-NE OATT (Yes/No)
789	3.45	3.45	Net Metering	Yes	No
1054	1.80	1.80	Qualifying Facility	No	No
11827	0.66	0.66	Net Metering	Yes	No
11889	0.05	0.05	Net Metering	Yes	No
16926	1.20	1.20	Qualifying Facility	No	No
37230	0.08	0.08	Net Metering	Yes	No
37965	0.16	0.17	Net Metering	Yes	No
40246	0.23	0.23	Net Metering	Yes	No
41821	0.10	0.10	Net Metering	Yes	No
41839	0.15	0.15	Net Metering	Yes	No
41847	0.10	0.10	Net Metering	Yes	No
42394	1.50	1.50	Net Metering	Yes	No
43492	4.50	4.50	Net Metering	Yes	No
43512	2.00	2.00	Net Metering	Yes	No
43527	0.50	0.50	Net Metering	Yes	No
43586	0.40	0.40	Net Metering	Yes	No
43607	0.50	0.50	Net Metering	Yes	No
43657	0.30	0.30	Net Metering	Yes	No
43685	0.12	0.12	DG Standard Contract Program	No	No
43716	2.00	2.00	DG Standard Contract Program	No	No
43762	3.00	3.00	DG Standard Contract Program	No	No
43871	2.00	2.00	Qualifying Facility	No	No
43921	0.14	0.14	DG Standard Contract Program	No	No
43956	0.50	0.50	Net Metering	Yes	No
44003	1.23	1.23	DG Standard Contract Program	No	No
44004	0.30	0.30	DG Standard Contract Program	No	No
44005	0.45	0.45	DG Standard Contract Program	No	No
44006	0.45	0.45	DG Standard Contract Program	No	No
44010	0.30	0.30	DG Standard Contract Program	No	No
46717	0.08	0.07	Net Metering	Yes	No
46721	0.25	0.25	DG Standard Contract Program	No	No
46911	0.85	0.85	DG Standard Contract Program	No	No
46913	0.19	0.19	DG Standard Contract Program	No	No
46917	0.05	0.05	DG Standard Contract Program	No	No
46926	0.06	0.06	DG Standard Contract Program	No	No
46998	0.07	0.07	DG Standard Contract Program	No	No
47020	0.50	0.50	DG Standard Contract Program	No	No
47283	0.19	0.19	Net Metering	Yes	No
47357	1.38	1.38	DG Standard Contract Program	No	No
47487	0.50	0.50	DG Standard Contract Program	No	No
48664	0.88	0.88	DG Standard Contract Program	No	No
48665	0.26	0.26	Net Metering	Yes	No
48758	0.08	0.08	Net Metering	Yes	No
48774	1.17	1.17	DG Standard Contract Program	No	No
48787	0.07	0.07	Net Metering	Yes	No
48788	0.14	0.14	Net Metering	Yes	No
49411	4.50	4.50	Net Metering	Yes	No
49412	4.50	4.50	Net Metering	Yes	No
49413	6.00	6.00	Net Metering	Yes	No
48811	0.09	0.09	Net Metering	Yes	No
48824	0.06	0.06	Net Metering	Yes	No
48899	1.00	1.00	DG Standard Contract Program	No	No
48913	0.10	0.10	Net Metering	Yes	No
49001	0.38	0.38	Net Metering	Yes	No
49222	0.15	0.15	Re-Growth	Yes	No
49241	0.20	0.20	Re-Growth	Yes	No
49254	0.20	0.20	Re-Growth	Yes	No
49256	0.20	0.20	Re-Growth	Yes	No
49289	0.03	0.03	Net Metering	Yes	No

Prepared by or under the supervision of: Vishal Ahirrao

Asset ID	(a) Nameplate Capacity (MW)	(b) Asset Registration Capacity (MW)	(c) Does Renewable Energy Program	(d) Will Facility Reduce National Grid's RNL (Yes/No)	(e) Facility will or will not reduce National Grid's Regional Network Load (RNL) under the Transmission Owners' prosed change to the definition of RNL in the ISO-NE OATT (Yes/No)
49292	0.38	0.38	Net Metering	Yes	No
49331	0.10	0.10	Net Metering	Yes	No
49354	0.18	0.18	Net Metering	Yes	No
49361	0.07	0.07	Net Metering	Yes	No
49404	0.12	0.12	Net Metering	Yes	No
49409	0.61	0.61	Net Metering	Yes	No
49414	0.03	0.03	Net Metering	Yes	No
49768	0.03	0.03	Net Metering	Yes	No
50057	3.20	3.20	DG Standard Contract Program	No	No
50060	1.12	1.12	Net Metering	Yes	No
50073	0.05	0.05	Net Metering	Yes	No
50072	0.22	0.22	Re-Growth	Yes	No
50078	0.13	0.13	Net Metering	Yes	No
50088	0.04	0.04	Net Metering	Yes	No
50128	0.20	0.20	Re-Growth	Yes	No
50197	0.11	0.11	Net Metering	Yes	No
50212	0.20	0.20	Re-Growth	Yes	No
50219	0.40	0.40	Re-Growth	Yes	No

PUC 1-14

Request:

To the Company's best knowledge, please provide a list of the other network customers who are served by the NEP local transmission network.

Response:

Please see below for other customers under NEP's local transmission service.

Customers in NEP's Network Service
The Narragansett Electric Company
Massachusetts Electric Company
Middleboro Municipal
Taunton Municipal
Pascoag
Liberty Energy (GSECO)
Island Corp.
ANP Bellingham
Milford Power Limited Partnership
City of Peabody
Town of Ashburnham
Town of Boylston
Town of Danvers
Town of Georgetown
Town of Groton
Town of Groveland
Town of Holden
Town of Hudson, Mass.
Town of Ipswich
Town of Littleton, Mass.
Town of Mansfield
Town of Marblehead
Town of Merrimac
Town of Middleton
Town of North Attleboro
Town of North Reading

Prepared by or under the supervision of: Alexei Spinu and Claude Houseman

Customers in NEP's Network Service
Town of Paxton
Town of Princeton
Town of Rowley
Town of Shrewsbury
Town of Sterling
Town of Templeton
Town of Wakefield
Town of West Boylston
Littleton, N.H.
Green Mountain Power Co.
Eversource Energy (East)
N. H. Electric Coop.
Eversource Energy (West)
Millennium Power Partners
Brookfield Energy Marketing
Great River Hydro
New Salem Harbor
Tanner St. Generation
Mass. Landbank
Dighton Power LLC
Hoosac Wind
Deepwater Wind
Vuelta Solar
Block Island
MBTA

Prepared by or under the supervision of: Alexei Spinu and Claude Houseman

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PUC 1-15

Request:

In his pre-filed testimony, Mr. Spinu identifies changes to the LNS formula rate that took effect on January 1, 2022, pursuant to the terms of the recent settlement approved by Federal Energy Regulatory Commission. Please provide an illustration (including illustrative data and calculations) of how LNS charges would have been allocated to Narragansett Electric under the old tariff vs. how they are allocated to Narragansett Electric under the approved settlement.

Response:

Please see Attachment PUC 1-15, which provides an illustration of how the LNS Revenue Requirement would have been assessed to Narragansett Electric using the previous LNS formula versus how the LNS Revenue Requirement will be assessed to Narragansett Electric under the currently effective formula.

For consistency, the comparison uses 2020 Non-PTF kW load data which was used to calculate the LNS rate effective January 1, 2022.

Prepared by or under the supervision of: Alexei Spinu

The Narragansett Electric Company
New vs Old LNS Non-PTF Demand Charge

Old LNS Non-PTF Demand Charge

The old LNS formula rate calculated the Non-PTF Revenue Requirement on a monthly basis and assessed charges to Narragansett Electric based on a load ratio share basis. For purposes of this comparison the estimated revenue requirement for CY 2022 and CY 2023 is used.

Line #	Period	(1) Non-PTF Load Ratio % Share	(2) Estimated Annual Non-PTF Revenue Requirement	(3) Non-PTF Demand Charge
1	April	23.48%	163,213,778	3,194,000
2	May	24.52%	163,213,778	3,335,307
3	June	28.01%	163,213,778	3,809,869
4	July	26.43%	163,213,778	3,594,574
5	August	25.64%	163,213,778	3,487,998
6	September	25.48%	163,213,778	3,465,920
7	October	25.22%	163,213,778	3,429,546
8	November	23.74%	163,213,778	3,228,326
9	December	23.66%	163,213,778	3,217,561
10	January	24.14%	170,972,885	3,439,145
11	February	23.78%	170,972,885	3,388,497
12	March	24.36%	170,972,885	3,471,202
13	**Total**			**41,061,946**

Notes
Line 1-12: Column (1) = Narragansett Electric Monthly Local Network Load Ratio % for CY2020
Line 1-12: Column (2) = Estimated Annual Non-PTF Revenue Requirement as per AS-7 Page 1 & Page 2
Line 1-12: Column (3) = Monthly Non-PTF Demand Charge as Load Ratio % * Annual Non-PTF Revenue Requirement. Annual Non-PTF Revenue Requirement as per AS-7 page 1 & 2
Line 13: Column (3) = Sum of lines 1-12

New LNS Non-PTF Demand Charge

The currently approved LNS formula rate calculates the Non-PTF Revenue Requirement on an annual basis and sets a LNS rate using annual LNS load for the most recent available calendar year. Narragansett Electric's actual monthly charge will be calculated using it's actual monthly Non-PTF load multiplied by the LNS rate.

Line #	Period	(1) Narragansett Non-PTF kW Load	(2) Monthly Local Network Service Rate	(3) Monthly Non-PTF Demand Charge
1	April	804,458	3.01	2,417,792
2	May	895,351	3.01	2,690,967
3	June	1,316,839	3.01	3,957,746
4	July	1,645,283	3.01	4,944,881
5	August	1,543,475	3.01	4,638,899
6	September	1,205,878	3.01	3,624,256
7	October	968,373	3.01	2,910,435
8	November	971,881	3.01	2,920,979
9	December	1,084,625	3.01	3,259,831
10	January	1,057,497	3.15	3,329,393
11	February	967,056	3.15	3,044,651
12	March	938,490	3.15	2,954,713
13		**1,116,601**	**3.04**	**40,694,544**

Notes
Line 1-12: Column (1) = Narragansett Electric Monthly Local Network Load (kW) for CY2020
Line 1-12: Column (2) = Estimated Monthly Non-PTF Service Rate as per AS-7 Page 1 & page 2
Line 1-12: Column (3) = Monthly Non-PTF Demand Charge as Monthly Load * Monthly LNS Rate Revenue Requirement. Monthly LNS Rate as per AS-7 page 1 & 2
Line 13: Column (3) = Sum of lines 1-12

PUC 1-16

Request:

Referencing Schedule AS-6, were Narragansett's non-PTF Load (kW) values that are listed in column (1) coincident with peak demand on the ISO-NE PTF system or the NEP local system?

Response:

The Non-PTF Load (kW) values listed in column (1) of Schedule AS-6, are coincident with peak demand on the NEP local system.

Prepared by or under the supervision of: Alexei Spinu

PUC 1-17

Request:

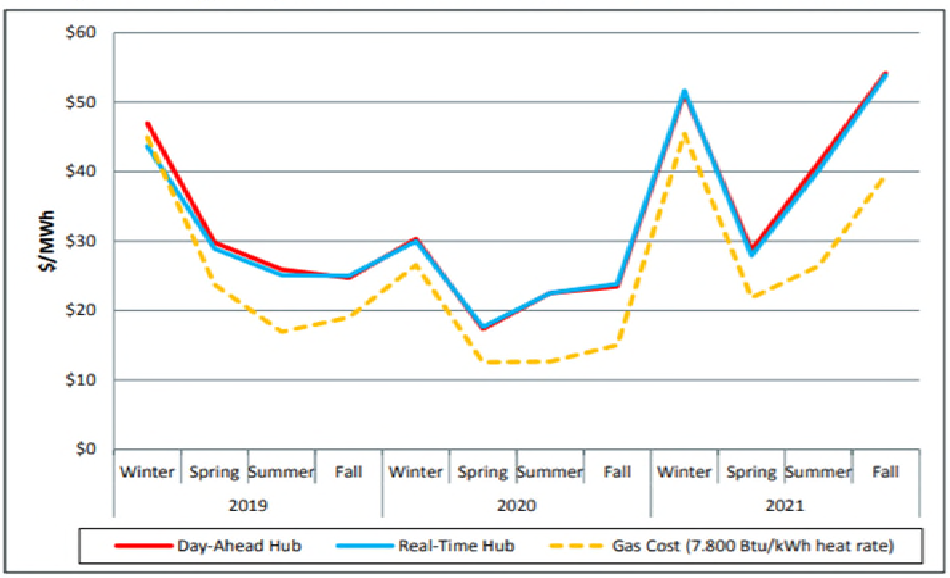
Referencing page 1 of Schedule NECO-16, it appears that between 2020 and 2021, total renewable generation credits increased by ~40% and ISO-NE energy sales proceeds increased by ~157%. Please explain the conditions that led to the value of energy sales to ISO-NE increasing so much faster between 2020 and 2021 than the value of total renewable generation credits during that same time.

Response:

Total Renewable Generation Credits in column (a) are total payments made to net metering customers in each month. In 2021, there were 80,962 more MWH (37.6% higher) upon which renewable generation credits were paid to net metering customers than in 2020.

Energy Sales to ISO-NE for Net Metered Customers in column (b) is the energy revenue received from ISO-NE for net metering assets that are registered with the ISO-NE. The ISO-NE credits the Company with Real Time Locational Marginal Prices (LMPs) for each hour of generation for each net metering asset registered with ISO-NE. 2021 Real Time LMPs have been significantly higher than 2020 Real Time LMPs as shown in the following graph:[1]

Figure 3-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



[1] Fall 2021 Quarterly Markets Report By ISO New England's Internal Marketing Monitor, January 25, 2022. https://www.iso-ne.com/static-assets/documents/2022/01/2021-fall-quarterly-markets-report.pdf

Prepared by or under the supervision of: Vishal Ahirrao and James Ruebenacker

PUC 1-17, page 2

Electric prices in New England are highly correlated with natural gas prices, and therefore Real Time LMPs have significantly increased in 2021 as the natural gas prices have increased. The increase in Real Time LMPs, combined with the increase in net metering generation, result in the 2021 Energy Sales to ISO-NE to be approximately 157% higher than the 2020 Energy Sales to ISO-NE.

PUC 1-18

Request:

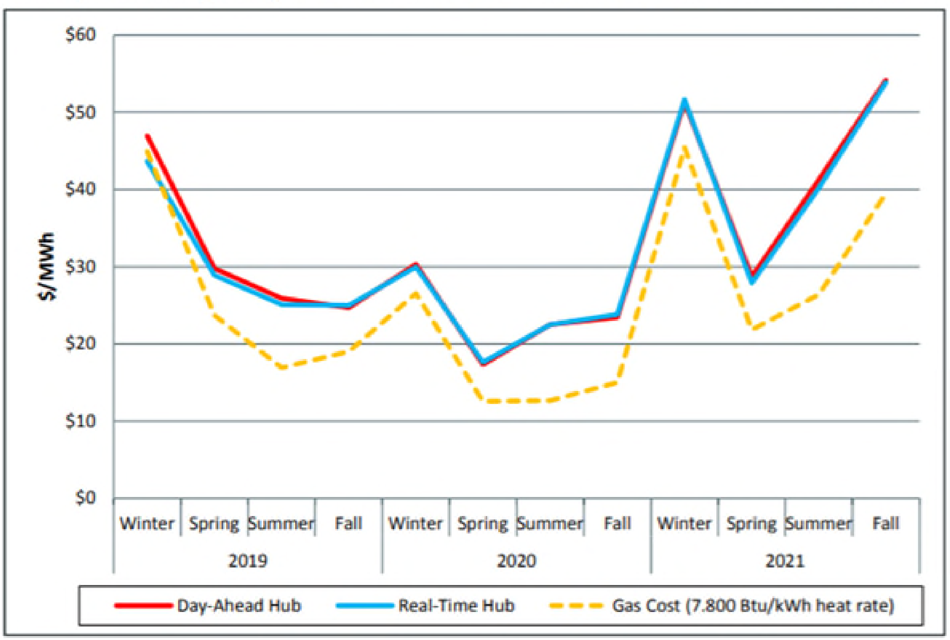
Between 2020 and 2021, why did Qualifying Facilities power purchase costs decrease from $678,949 (Schedule NG-16 in Docket No. 5127) to $266,134 (page 1 of Schedule NECO-16)?

Response:

The Qualifying Facilities Power Purchase Recoverable Costs, column (c), on page 1 of Schedule NECO-16 is the difference between the payments made to Qualifying Facilities ("QF") with renewable generation at the Last Resort Service ("LRS") rates and the net proceeds received from ISO-NE for market energy sold and capacity payments. An increase in the net proceeds from ISO-NE, or a decrease in QF payment rates, will decrease the differences in column (c).

ISO-NE credits the Company with the Real Time Locational Marginal Prices ("LMPs") for each hour of generation for each QF asset registered with ISO-NE. 2021 Real Time LMPs have been significantly higher than 2020 Real Time LMPs as shown in the following graph:[1]

Figure 3-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



[1] Fall 2021 Quarterly Markets Report By ISO New England's Internal Marketing Monitor, January 25, 2022. https://www.iso-ne.com/static-assets/documents/2022/01/2021-fall-quarterly-markets-report.pdf

Prepared by or under the supervision of: James Ruebenacker

PUC 1-18, page 2

The increase in Real Time LMPs in 2021 resulted in higher ISO-NE energy revenues for 2021 compared to 2020. Additionally, the QF payment rates, which are LRS rates, were lower in 2021 compared to 2020. Therefore, the lower QF payment rates and the higher ISO-NE revenues in 2021 resulted in the net cost decreasing from $678,949 in 2020 to $266,134 in 2021.

Prepared by or under the supervision of: James Ruebenacker

PUC 1-19

Request:

On page 1 of Schedule NECO-16, the Company includes footnote d that reads "July 2021: Credit to customers due to there being no wholesale energy revenue associated with Net Metering credits provided to a facility in advance of its registration with ISO-NE." Please explain this footnote in greater detail.

Response:

R.I.P.U.C. No. 2241, the Company's Net Metering Provision, requires Net Metering customers who install Eligible Net Metering Systems with a nameplate capacity in excess of 25 kW to comply with any and all applicable NEPOOL and ISO-NE rules, requirements, or information requests that are necessary for the Eligible Net Metering System's electric energy output to be sold into the ISO-NE administered markets. If the Company must provide to NEPOOL or ISO-NE any information regarding the operation, output, or any other data in order to sell the output of the Eligible Net Metering System into the ISO-NE administered markets, the Net Metering customer who installs an Eligible Net Metering System must provide such information to the Company prior to the project being authorized to operate in parallel with the Company's electric distribution system.

The Company typically assists Net Metering customers with Eligible Net Metering systems that are greater than 25 kW and below 5 MW to complete their registration by submitting their Generator Asset Registration Forms ("GARF"). In this instance, when the Company submitted a GARF to ISO-NE after the customer's bidirectional meter was installed, ISO-NE informed the Company and the customer that it considered the project to be over 5 MW because of other generation behind the same Point of Interconnection and thus, the system must be registered as a "Model Only Generator," and meet the associated ISO-NE requirements for such systems. Between the time customer was authorized to operate in parallel and until the system had satisfied all ISO-NE requirements and was registered as a Model Only Generator, the Company did not receive wholesale revenue to offset the Renewable Generation Credits issued to the customer. The July 2021 credit represents the value of the energy generated and exported, had the energy been sold and had the Company received proceeds from ISO-NE. The Company charged the customer the amount of this adjustment on the customer's electricity bill.

Prepared by or under the supervision of: Vishal Ahirrao

PUC 1-20

Request:

The Net Metering Report indicates that 44+ MW of large, likely standalone facilities were interconnected in December 2021. With regards to these facilities, please explain the following:

a. Describe the extent to which the proposed 2022 Net Metering Charge reflects the costs imposed by these 44+ MW.
b. In response to PUC 1-15 in Docket No. 5127, the Company explained that the increase in the Net Metering Charge between 2019 and 2020 resulted, in part, from the interconnection of 41.6 MW in December 2019. The Company wrote "accordingly, a full year of Renewable Generation Credits associated with the 41.6 MW [interconnected in 2019] are part of the 2020 costs," as opposed to the 2019 costs. Regarding the 44+ MW of net metering facilities interconnected in December 2021, when will the Net Metering Charge reflect the cost of a full year of Renewable Generation Credits associated with the 44+ MW interconnected in December 2021?

Response:

a. The 44+ MW connected in December 2021 would not have an impact on the proposed 2022 Net Metering Surcharge. The 2022 Net Metering Surcharge recovers Renewable Generation Credits appearing on projects' bills issued during 2021. Projects that connected in December 2021 would not have received their first bill during December 2021, would not have received a Renewable Generation Credit, and therefore would not have an impact on the proposed 2022 Net Metering Surcharge. These projects will have an impact on 2022 net metering costs and consequently the 2023 Net Metering Surcharge.

b. The projects that were connected in 2019 impacted 2020 net metering costs and the 2021 Net Metering Surcharge because they had 12 months of generation and Renewable Generation Credits in 2020 that were included for recovery in the 2021 Net Metering Surcharge. Therefore, the projects that connected in December 2021 would not impact the Net Metering Surcharge until 2023.

Prepared by or under the supervision of: Vishal Ahirrao and Felicia Marcello

PUC 1-21

Request:

Please update your response to PUC 1-18 in Docket No. 5127 with 2021 data.

Response:

Please see the below tables for the requested information.

PUC 1-21, page 2

Net Metering Credit Monetary Value (Renewable Generation Credits)
Total

	A16	A60	C06	G02	G32	Total
2009	($2,805)	($70)	($1,170)	$0	($240,647)	($244,692)
2010	($4,552)	($99)	($1,028)	$0	($329,863)	($335,542)
2011	($4,494)	($35)	($2,969)	($850)	($214,875)	($223,223)
2012	($7,846)	($248)	($13,987)	($1,629)	($143,176)	($166,886)
2013	($12,772)	($640)	($34,986)	($1,547)	($3,274)	($53,218)
2014	($26,144)	($821)	($37,858)	($9,483)	$0	($74,306)
2015	($49,771)	($1,668)	($61,054)	($14,760)	($1,714)	($128,967)
2016	($144,746)	($1,070)	($1,185,899)	($16,402)	($3,013)	($1,351,130)
2017	($209,665)	($1,838)	($3,697,933)	($13,298)	($11,218)	($3,933,952)
2018	($286,830)	($3,163)	($5,188,377)	($27,279)	$0	($5,505,651)
2019	($573,013)	($11,989)	($20,542,686)	($55,504)	($306)	($21,183,499)
2020	($745,732)	($12,141)	($33,434,468)	($74,621)	($136)	($34,267,098)
2021	($1,053,281)	($20,087)	($46,581,096)	($102,161)	$0	($47,756,626)

Net Metering Credit Volume (kWh Exported - Generation in excess of Use)
Total

	A16	A60	C06	G02	G32	Total
2009	(19,593)	(648)	(7,942)	-	(2,113,159)	(2,141,342)
2010	(31,037)	(746)	(7,099)	-	(3,460,321)	(3,499,203)
2011	(35,969)	(330)	(24,298)	(9,990)	(2,663,399)	(2,733,986)
2012	(61,246)	(2,263)	(90,736)	(19,813)	(1,705,789)	(1,879,847)
2013	(88,169)	(4,955)	(237,664)	(16,544)	(39,175)	(386,507)
2014	(181,746)	(6,333)	(270,722)	(96,289)	-	(555,090)
2015	(305,642)	(8,189)	(392,578)	(118,565)	(23,742)	(848,716)
2016	(945,801)	(7,663)	(8,034,352)	(179,170)	(47,686)	(9,214,672)
2017	(1,471,497)	(14,657)	(26,084,334)	(149,160)	(6,437)	(27,726,085)
2018	(1,753,055)	(21,273)	(31,777,494)	(270,604)	-	(33,822,426)
2019	(3,284,454)	(69,300)	(119,982,615)	(547,594)	(2,857)	(123,886,820)
2020	(4,512,528)	(74,328)	(209,935,158)	(806,052)	(1,574)	(215,329,640)
2021	(6,227,382)	(120,391)	(288,849,002)	(1,094,334)	-	(296,291,109)

Prepared by or under the supervision of: Vishal Ahirrao and Felicia Marcello

PUC 1-21, page 3

Net Metering Credit Monetary Value (Renewable Generation Credits)
Remote Facilities

	A16	A60	C06	G02	G32	Total
2009	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0
2011	$0	$0	$0	$0	$0	$0
2012	$0	$0	$0	$0	$0	$0
2013	$0	$0	$0	$0	$0	$0
2014	$0	$0	$0	$0	$0	$0
2015	$0	$0	$0	$0	$0	$0
2016	$0	$0	($686,409)	$0	$0	($686,409)
2017	$0	$0	($3,597,967)	$0	$0	($3,597,967)
2018	$0	$0	($5,061,467)	$0	$0	($5,061,467)
2019	$0	$0	($20,346,614)	$0	$0	($20,346,614)
2020	$0	$0	($33,124,661)	$0	$0	($33,124,661)
2021	$0	$0	($46,079,113)	$0	$0	($46,079,113)

Net Metering Credit Volume (kWh Exported - Generation in excess of Use)
Remote Facilities

	A16	A60	C06	G02	G32	Total
2009	-	-	-	-	-	-
2010	-	-	-	-	-	-
2011	-	-	-	-	-	-
2012	-	-	-	-	-	-
2013	-	-	-	-	-	-
2014	-	-	-	-	-	-
2015	-	-	-	-	-	-
2016	-	-	(4,746,533)	-	-	(4,746,533)
2017	-	-	(21,353,938)	-	-	(21,353,938)
2018	-	-	(29,957,752)	-	-	(29,957,752)
2019	-	-	(104,818,490)	-	-	(104,818,490)
2020	-	-	(207,953,292)	-	-	(207,953,292)
2021	-	-	(286,711,734)	-	-	(286,711,734)

Prepared by or under the supervision of: Vishal Ahirrao and Felicia Marcello

PUC 1-21, page 4

Net Metering Credit Monetary Value (Renewable Generation Credits)
Behind the Meter

	A16	A60	C06	G02	G32	Total
2009	($2,805)	($70)	($1,170)	$0	($240,647)	($244,692)
2010	($4,552)	($99)	($1,028)	$0	($329,863)	($335,542)
2011	($4,494)	($35)	($2,969)	($850)	($214,875)	($223,223)
2012	($7,846)	($248)	($13,987)	($1,629)	($143,176)	($166,886)
2013	($12,772)	($640)	($34,986)	($1,547)	($3,274)	($53,218)
2014	($26,144)	($821)	($37,858)	($9,483)	$0	($74,306)
2015	($49,771)	($1,668)	($61,054)	($14,760)	($1,714)	($128,967)
2016	($144,746)	($1,070)	($499,490)	($16,402)	($3,013)	($664,721)
2017	($209,665)	($1,838)	($99,966)	($13,298)	($11,218)	($335,985)
2018	($286,830)	($3,163)	($126,910)	($27,279)	$0	($444,183)
2019	($573,013)	($11,989)	($196,072)	($55,504)	($306)	($836,885)
2020	($745,275)	($9,843)	($317,719)	($69,464)	($136)	($1,142,437)
2021	($1,053,281)	($20,087)	($501,982)	($102,161)	$0	($1,677,513)

Net Metering Credit Volume (kWh Exported - Generation in excess of Use)
Behind the Meter

	A16	A60	C06	G02	G32	Total
2009	(19,593)	(648)	(7,942)	-	(2,113,159)	(2,141,342)
2010	(31,037)	(746)	(7,099)	-	(3,460,321)	(3,499,203)
2011	(35,969)	(330)	(24,298)	(9,990)	(2,663,399)	(2,733,986)
2012	(61,246)	(2,263)	(90,736)	(19,813)	(1,705,789)	(1,879,847)
2013	(88,169)	(4,955)	(237,664)	(16,544)	(39,175)	(386,507)
2014	(181,746)	(6,333)	(270,722)	(96,289)	-	(555,090)
2015	(305,642)	(8,189)	(392,578)	(118,565)	(23,742)	(848,716)
2016	(945,801)	(7,663)	(3,287,819)	(179,170)	(47,686)	(4,468,139)
2017	(1,471,497)	(14,657)	(4,730,396)	(149,160)	(6,437)	(6,372,147)
2018	(1,753,055)	(21,273)	(1,819,742)	(270,604)	-	(3,864,674)
2019	(3,284,454)	(69,300)	(15,164,125)	(547,594)	(2,857)	(19,068,330)
2020	(4,515,327)	(74,328)	(2,008,492)	(776,627)	(1,574)	(7,376,348)
2021	(6,227,382)	(120,391)	(2,137,268)	(1,094,334)	-	(9,579,375)

Prepared by or under the supervision of: Vishal Ahirrao and Felicia Marcello

PUC 1-22

Request:

Please update your response to PUC 1-19 in Docket No. 5127 with 2021 data.

Response:

The source for the information provided in response to PUC 1-19 in Docket No. 5127 was the Company's billing system (i.e., CSS), which does not track the special entity types identified in the Net Metering tariff. However, the Company has attempted to distinguish and group these "Front-of-the-Meter" projects, by using host customer names and associated off-takers, in two tables, below.

Net Metering Credit Monetary Value (Renewable Generation Credits)

Type	2016 $	2017 $	2018 $	2019 $	2020 $	2021 $
Municipality	($134,151)	($1,573,477)	($1,765,103)	($10,369,569)	($17,203,159)	($17,512,244)
Multi-Municipal Collaborative	($552,258)	($2,024,490)	($3,113,282)	($6,722,375)	($8,392,926)	($10,698,817)
Educational Institutes	0	0	($120,784)	($1,780,907)	($2,444,285)	($5,756,934)
Public Entity & Low Income Housing	0	0	0	($1,024,827)	($1,794,681)	($1,812,694)
Public Entity	0	0	($62,298)	($263,022)	($2,110,588)	($4,379,098)
Community Remote Net Metering	0	0	0	($185,914)	($650,397.00)	($3,412,653)
Total	($686,409)	($3,597,967)	($5,061,467)	($20,346,614)	($32,596,038)	($43,572,440)

Net Metering Credit Volume (kWh Exported - Generation in excess of Use)

Type	2016 kWh	2017 kWh	2018 kWh	2019 kWh	2020 kWh	2021 kWh
Municipality	(927,228)	(7,107,979)	(9,660,582)	(47,850,838)	(108,634,758)	(106,132,012)
Multi-Municipal Collaborative	(3,819,305)	(14,245,959)	(19,270,146)	(37,850,600)	(53,535,270)	(69,849,945)
Educational Institutes	0	0	(661,607)	(10,549,153)	(15,469,615)	(35,956,977)
Public Entity & Low Income Housing	0	0	0	(5,929,326)	(11,139,673)	(11,124,866)
Public Entity	0	0	(365,417)	(1,544,129)	(13,175,364)	(27,150,937)
Community Remote Net Metering	0	0	0	(1,094,444)	(4,098,736)	(21,736,962)
Total	(4,746,533)	(21,353,938)	(29,957,752)	(104,818,490)	(204,053,416)	(271,951,699)

Prepared by or under the supervision of: Vishal Ahirrao and Felicia Marcello

PUC 1-23

Request:

Referencing the Company's response to PUC 7-1 in Docket No. 5127, please update the response with 2 new tables: one for CY 2021 Volumetric Method and one for CY 2021 Monetary Method.

Response:

Please find tables comparing the Volumetric and Monetary Methods for CY 2019, CY 2020, and CY 2021 below.

Table 1 – CY 2019 Volumetric Method

2019 Volumetric	**Greater than 25 kW**		**Less than 25 kW**	**Total**
	BTM	**Standalone**	**BTM**	
Number of Net Metering Systems	13	5	620	**638**
Total Excess Credits ($)	$19,711	$609,536	$85,684	**$714,931**
Total Excess Generation (kWh)	249,153	2,639,962	818,461	**3,707,576**
Total Charge ($)	$18,319	$202,289	$87,724	**$308,333**
Minimum Charge for BTM Projects ($) (Docket No. 5127 PUC 7-3)	$11,962	N/A	$65,175	**$77,137**

Table 2 – CY 2019 Monetary Method

2019 Monetary	**Greater than 25 kW**		**Less than 25 kW**	**Total**
	BTM	**Standalone**	**BTM**	
Number of Net Metering Systems	10	24	506	**540**
Total Excess Credits ($)	$22,214	$2,651,199	$98,277	**$2,771,690**
Total Excess Generation (kWh)	124,593	14,954,867	523,173	**15,602,634**
Total Charge ($)	$13,561	$1,452,124	$52,575	**$1,518,260**
Minimum Charge for BTM Projects ($) (Docket No. 5127 PUC 7-3)	$9,448	N/A	$41,626	**$51,074**

PUC 1-23, page 2

Table 3 – CY 2020 Volumetric Method

2020 Volumetric	**Greater than 25 kW**		**Less than 25 kW**	**Total**
	BTM	**Standalone**	**BTM**	
Number of Net Metering Systems	26	12	831	**869**
Total Excess Credits ($)	$31,470	$839,385	$91,429	**$962,284**
Total Excess Generation (kWh)	588,561	10,185,472	1,122,218	**11,896,251**
Total Charge ($)	$51,732	$918,506	$125,545	**$1,095,782**
Minimum Charge for BTM Projects ($) (Docket No. 5127 PUC 7-3)	$31,470	N/A	$91,429	**$122,899**

Table 4 – CY 2020 Monetary Method

2020 Monetary	**Greater than 25 kW**		**Less than 25 kW**	**Total**
	BTM	**Standalone**	**BTM**	
Number of Net Metering Systems	17	40	661	**718**
Total Excess Credits ($)	$56,008	$8,267,819	$140,835	**$8,464,662**
Total Excess Generation (kWh)	349,122	49,481,234	779,721	**50,610,077**
Total Charge ($)	$38,890	$6,059,917	$86,732	**$6,185,539**
Minimum Charge for BTM Projects ($) (Docket No. 5127 PUC 7-3)	$26,108	N/A	$67,331	**$93,439**

Table 5 – CY 2021 Volumetric Method

2021 Volumetric	**Greater than 25 kW**		**Less than 25 kW**	**Total**
	BTM	**Standalone**	**BTM**	
Number of Net Metering Systems	26	19	1,094	**1139**
Total Excess Credits ($)	$57,288	$2,641,396	$170,789	**$2,869,472**
Total Excess Generation (kWh)	706,912	16,314,073	1,456,914	**18,477,899**
Total Charge ($)	$65,639	$1,920,289	$172,350	**$2,158,279**
Minimum Charge for BTM Projects ($) (Docket No. 5127 PUC 7-3)	$37,518	N/A	$132,131	**$169,648**

Prepared by or under the supervision of: Vishal Ahirrao and Felicia Marcello

PUC 1-23, page 3

Table 6 – CY 2021 Monetary Method

2021 Monetary	**Greater than 25 kW**		**Less than 25 kW**	**Total**
	BTM	**Standalone**	**BTM**	
Number of Net Metering Systems	21	42	730	**793**
Total Excess Credits ($)	$58,962	$6,685,917	$177,345	**$6,922,224**
Total Excess Generation (kWh)	354,390	39,697,883	944,176	**40,996,449**
Total Charge ($)	$44,671	$ 4,485,320	$114,843	**$4,644,833**
Minimum Charge for BTM Projects ($) (Docket No. 5127 PUC 7-3)	$29,618	N/A	$85,849	**$115,467**

Prepared by or under the supervision of: Vishal Ahirrao and Felicia Marcello

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PUC 1-24

Request:

In Schedule NECO-17 (the Net Metering Report), the Company lists 3 small-scale wind-powered net metering facilities that were interconnected in 2021: Facility ID 333296 (5 kW), 338451 (6 kW), and 345575 (10 kW). Please confirm that these facilities are wind-powered, and were not inadvertently tagged as such.

Response:

Facility ID 333296 (5 kW), 338451 (6 kW), and 345575 (10 kW) are solar-powered facilities, not wind-powered. The necessary updates have been made in the portal to accurately reflect the data in future reporting.

PUC 1-25

Request:

Please update the response to PUC 1-23 in Docket N0. 5127 to explain the difference between LTC revenue and expense (page 1 of Schedule NECO-18) that occurred in 2021.

Response:

The over-recovery resulting from the LTC reconciliation in Schedule NECO-18 is driven predominantly by the difference between estimated LTC costs in the semi-annual LTCRER Factor filings and actual LTC costs incurred and included in the reconciliation. Table A shows calendar year 2021 estimated and actual LTC costs.

Table A.

	Description	Estimate	Actual	Actual Costs Higher/ (Lower) than Estimated
1	Above Market Costs	$41,133,552	$31,984,361	($9,149,191)
2	Customer Share of Net Forward Capacity Market Proceeds	($140,466)	($136,570)	$3,896
3	Administrative Costs	$25,344	$30,896	$5,552
4	Remuneration	$0	$2,190,241	$2,190,241
5	Other Charges & (Credits)	$0	($22,570)	($22,570)
6	Total Costs	$41,018,430	$34,046,358	($6,972,072)

The $9,149,191 decrease in above market costs shown in Table A on Line 1 was caused by the following factors:

Table B.

	Description	$M
1	Lower contract costs due to decreased MWh Output of 103,697.7	($14.7)
2	Higher Energy Market Value	$1.6
3	Higher REC Market Value	$3.9
4	Total	($9.2)

Prepared by or under the supervision of:
Daniel Gallagher, Stephanie Briggs and Jeffrey Oliveira

PUC 1-25, page 2

Explanations of the items from Table B:

1. Lower MWh production from the following LTC units, as well as small changes (increases and decreases) in MWh production from other units:

Unit	MWh Decrease from Estimate
Copenhagen Wind Farm	(36,882.0)
Deepwater Wind	(34,727.3)
Black Bear Orono B Hydro	(4,476.4)
Cassadaga Wind	(19,811.8)
RI LFG Genco	(5,006.0)
Total	(100,903.5)

PUC 1-26

Request:

Referencing page 4 of Schedule NECO-18, please explain why FCM Admin Expenses increased from $9,948 in 2020 to $30,896 in 2021.

Response:

The main driver is the inclusion of FCM Admin Cost from calendar year 2020 which were inadvertently excluded from last year's Annual Retail Rate Filing. These costs were included in the month of November 2021.

Of the $20,149 reflected in November 2021, $15,174 was incurred during calendar year 2020 and therefore should have been included for recovery in the Company's 2021 Annual Retail Rate Filing in R.I.P.U.C. Docket No. 5127. In other words, the $9,948 in total FCM Admin Cost for 2020 as presented in last year's Annual Retail Rate Filing on Schedule NG-18, Page 4, Column (k) was under-stated by $15,174, and should have been $25,122. FCM Admin Cost incurred during calendar year 2021 was $15,722. The Company is seeking recovery of $30,896 which represents the 2021 costs plus the 2020 costs that were inadvertently left out of last year's plan.

Prepared by or under the supervision of:
Daniel Gallagher, Stephanie Briggs, Jeffrey Oliveira, and Rachel Dugan

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PUC 1-27

Request:

For the period of April 2022 – March 2023, the Company forecasts retail deliveries of 7,368,760,169 kWh. This appears to be the first time in at least five years that the Company is forecasting a year-over-year increase in retail deliveries. Please explain the drivers of this increase. In your response, explain whether the total increase is driven primarily by individual customer classes or groups, and the specific reasons for those class/group increases.

Response:

The forecast in this filing was from the Company's annual forecasting process conducted in Fall 2021. For the period of April 2022 – March 2023 (i.e., the fiscal year 2023 or FY2023), the Company forecasted the retail deliveries to increase by 1.1% from the previous fiscal year of 2022 (i.e., FY2022, which has actual from April 2021 to August 2021 and forecasted value from September 2021 to March 2022). The forecasted growth in energy and the change in how energy efficiency programs were considered in the Company's load forecasting process contributed to the forecasted growth for FY2023.

The forecasted energy growth in the residential, commercial, and industrial revenue classes are first discussed below, followed by the discussions on how energy efficiency programs were considered in the load forecasting process.

- Residential sector
  The residential energy consumption had grown significantly during the pandemic in FY2021 (i.e., 7.5% from the previous fiscal year) and still stayed at a high level post-pandemic when the Company conducted its forecasting in Fall 2021. The Company considered these recent residential energy consumption trends and the outlook on the forecasted growth in the number of households in the region from Moody's Economic Outlook released in August 2021. These supported the forecasted continuous growth in the residential sector in FY2023. This also aligns with the overall long-term growth trend in the residential sector.

- Commercial sector
  The commercial sector had a significant decline during the pandemic in FY2021 (i.e., 3.2%) but has shown a strong rebound in FY2022 (i.e., 1.4% growth from FY2021) when the Company conducted its forecasting in Fall 2021. For FY2023, based on the recent growth in commercial energy usage and the forecasted growth in the regional number of households from Moody's Economic Outlook (a growth in households generally supports the growth in the local commercial), the Company forecasted the commercial sector will

continue recovering from the loss happened in the pandemic and reach a close to its pre-pandemic level in FY2023.

- Industrial sector
  The industrial sector had a very significant decline during the pandemic in FY2021 (i.e., 8.0%) but has shown some moderate rebound in FY2022 when the Company conducted its forecasting in Fall 2021. However, the forecast on the manufacturing employment from Moody's Economic Outlook does not support a significant rebound of the industrial sector back to its pre-pandemic level in the near-term; thus, the Company only predicted a very mild growth in the industrial sector, but it would still be below its pre-pandemic level. The energy usage of the Company's industrial sector has declined year-over-year in the past ten years, the industrial energy may never return to its pre-pandemic level in the foreseen longer term.

Furthermore, the Company re-analyzed the impacts of its energy efficiency programs: persistent and non-persistent savings were differentiated to more accurately account for the accumulation of claimable savings over time. Non-persistent savings from behavioral programs like the home energy report do not accumulate over time but was only considered as savings / reducing-energy for that year. Savings from persistent programs do accumulate over time (i.e., lighting programs). As a result, the estimated impacts from energy savings decreased quite a bit comparing the forecasts on cumulative energy efficiency savings from previous years: comparing with the Company's Fall 2020 forecast, the estimated savings from the cumulative energy efficiency program reduced by 240 GWh or 9.0% in our load forecasting for FY2023, comparing to the Company's Fall 2020's projection for the same period.

Prepared by or under the supervision of: Joseph Gredder and Jingrui Xie

PUC 1-28

Request:

In response to PUC 1-24 in Docket No. 5127, the Company explained that the development of the electric heat component of its retail deliveries forecast only considered residential heat pump adoption. For the retail deliveries forecast used in Docket No. 5234 (April 2022 – March 2023), did the Company only consider residential heat pump adoption?

Response:

The Company used ISO-NE's 2021 residential electrification forecast as a basis for its own forecast in Rhode Island. This is appropriate as the Company's electrification efforts focus on residential customers in the near-term, including the period April 2022 through March 2023. Thus, no commercial electric heat pump adoption is projected in the Company's retail deliveries forecast used in Docket No. 5234 (April 2022 – March 2023). The Company will continue to monitor the appropriateness of additional electrification assumptions for each revenue class (residential, commercial, industrial) in future forecasts.

Prepared by or under the supervision of: Joseph Gredder and Jingrui Xie