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MEMORANDUM

To: RHODE ISLAND PUBLIC UTILITIES COMMISSION

From: Carrie Gilbert and Aliea Afnan Munger, DAYMARK ENERGY ADVISORS

Date: March 16, 2022

Subject: National Grid's 2022 Retail Electric Rate Filing – Docket No. 5234

INTRODUCTION

On February 15, 2022, National Grid ("NGrid" or "the Company") filed its 2022 Retail Rate Filing. This filing consists of rate adjustments primarily arising out of the reconciliation of the Company's Last Resort Service ("LRS"), LRS administrative costs, the non-bypassable transition charge, transmission service charge, the transmission-related uncollectible expense charge, the Net Metering Charge, and the Long-Term Contracting for Renewable Energy Recovery Factor ("LTC Recovery Factor"). The reconciliation period for the various costs in this filing is January 2021 through December 2021. The proposed rate adjustments are effective for usage on and after April 1, 2022. The net effect of all proposed rate changes for a residential LRS customer using 500/kWh per month is an increase of $0.81 or 0.7%. Based on the Public Utilities Commission's (PUC's) Orders in Dockets 4599 and 4691, the Company has provided Excel files of its workpapers supporting the 2022 Annual Retail Rates Filing. This filing was designated as Docket No. 5234.

The Rhode Island Division of Public Utilities and Carriers (the "Division") has retained Daymark Energy Advisors to assist in its review of this filing to ensure the various reconciliations are accurately calculated and are in accordance with the relevant tariffs. In summary, we find that NGrid calculated all the charges appropriately based on the underlying data the Company presented and the Company's tariff.

This memorandum presents the full results of our review.

LAST RESORT SERVICE ADJUSTMENT FACTORS

The Company is proposing to adjust two LRS-related rate charges: (1) an adjustment factor to collect (or refund) net under (or over) recovery of LRS expense and (2) the LRS administrative cost adjustment factor, which is the sum of an administrative cost factor designed to collect various projected administrative expenses related to the provision of LRS and an LRS administrative cost reconciliation adjustment factor, which accounts for any under- or over-recovery of prior period LRS administrative costs.

For the first charge, the LRS reconciliation adjustment, the filing at Schedule NECO-2, p. 1, shows a net over-recovery (with interest) of approximately $1.7 million in calendar year ("CY") 2021, compared to the over-recovery (with interest) of approximately $9.6 million in CY 2020. This CY 2021 total is a sum of the separately calculated totals for each of the three LRS customer groups: Residential, Commercial, and

Industrial. These totals are then adjusted for additional interest during the recovery period and divided by forecasted customer group LRS kWh sales for April 2021 through March 2022 to calculate three different adjustment factors, one for each procurement group. The Residential group had an over-recovery (with interest) of approximately $9.2 million. The Commercial and Industrial groups had under-recoveries (with interest) of $6.7 million and $0.78 million, respectively.[1]

Additionally, as a result of Order 23366 in Docket 4809, the Company began removing capacity costs from the full requirement services contracts used to procure power for the three customer groups and included estimates of capacity payments in Standard Offer Service (SOS)[2] rates beginning in April 2019.[3] These calculations show that there were over-recoveries of capacity costs for residential and industrial customers of $10.9 million and $0.2 million and an under-recovery for commercial customers of $2.3 million.[4] According to the Testimony of Gallagher, Briggs, Oliveira, Ahirrao, these costs are inherently included in the over/under-recovery balance of the LRS base reconciliation shown on pages 2-4 of Schedule NECO-2 and contribute to the total over- or under- recovery for each class.[5]

The LRS reconciliation adjustment for CY 2021 includes the additional following adjustments: $1,780,161 reflecting the remaining balance of CY 2019 net under-recovery SOS expenses; and further reduced by the LRS reconciliation by $4,344 for unbilled SOS Billing Adjustments for CY 2020. The net unbilled billing adjustment revenue for CY 2021 is the combination of a negative $7,439[6] for Residential and a positive $3,095[7] for Commercial LRS customers. These amounts equate to a credit or revenue surplus of $4,344[8] as the Company paid less for the LRS supply than it billed to customers that left LRS and took electric supply from a third party.[9] NGrid is proposing this amount as an adjustment to the Revenue Decoupling Mechanism ("RDM")[10] reconciliation, which will be filed by May 15, 2022.[11] Through the RDM Adjustment Factor, all customers will be assessed a portion of the net LRS Billing Adjustment credit.

On a per kWh basis, the charge with the largest magnitude LRS adjustment is a 0.665 cents/kWh charge for the Commercial class.[12] This is compared to a CY 2021 charge of 0.568 cents/kWh. In response to Data Request PUC 1-27, the Company explained that the Commercial sector had a significant decline during the COVID-19 pandemic in FY2021 and has shown a strong rebound in FY2022.

The LRS adjustment for the Residential class is a credit of 0.318 cents/kWh compared to a credit of 0.512 cents/kWh last year. The Industrial class will be charged 0.375 cents/kWh compared to a credit of 0.598

[1] Schedule NECO-2, p. 2-4.
[2] Standard Offer Service expired December 31, 2020, and Last Resort Service became effective January 1, 2021.
[3] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p. 12, line 21, lines 10-13.
[4] Schedule NECO-2, p. 7.
[5] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p. 13, lines 3-4.
[6] Schedule NECO-2, p. 2.
[7] Schedule NECO-2, p. 3.
[8] Schedule NECO-2, p. 1.
[9] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p. 21, lines 17-21.
[10] The RDM Adjustment Factor is a uniform per kWh factor applicable to all retail delivery service customers.
[11] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p. 22, lines 7-9.
[12] Schedule NECO-3, p. 1.

cents/kWh last year.[1] When asked in Docket 4805 about the swings in net over- and under-recovery to the different LRS groups, the Company provided four factors that can contribute to these swings: (1) Fixed prices for the Residential and Commercial classes are developed using monthly kWh estimates that may differ from the actual monthly distribution across the rate period; (2) line losses used to develop LRS retail rates are estimated and may vary from actual line losses; (3) estimated spot market prices are used to develop the retail LRS rates and actual spot market prices may differ; and (4) customers are billed on a billing cycle basis while the Company is billed for LRS expenses on a calendar month basis.[2] Our review indicates the LRS reconciliation adjustment factors are consistent with the underlying data and tariff R.I.P.U.C. No. 2237 and are reasonable.

The Administrative Cost Factor includes an allowance for LRS uncollectible expense and several administrative cost elements (chief of which is cash working capital). The 2022 filing shows total administrative expense of approximately $8.47 million[3] compared to approximately $7.64 million in the 2021 filing. The cash working capital requirement is $48.1 million[4], compared to $43.9 million in the 2021 filing. This increase was mostly due to an increase in the customer payment lag from an average of 72 days in 2020 to 76 days[5] in 2021.

As with the LRS Adjustment Factor, separate LRS Administrative Cost Factors are calculated for the three customer groups. The estimated LRS Administrative Cost Factor is calculated by dividing the customer group's portion of the Administrative Cost Factor by the estimated kWh sales for that customer group. The LRS Administrative Cost Reconciliation Adjustment Factor for each class is then added to the estimated LRS Administrative Cost Factor to yield the final LRS Administrative Cost Factor.

LRS Administrative Cost Reconciliation Adjustment Factor is based upon the over- or under-collection of administrative costs for the prior year. For the 2022 filing, the Company reports a net under-collection of 2021 administrative costs of approximately $1.1 million (with interest).[6] The Residential, Commercial, and Industrial customer groups showed under-collections of $759,739, $292,894, and $70,840 respectively.[7] This net under-collection is largely due to a combination of higher expenses than revenues for all three customer groups.

Both the estimated administrative costs and under-collection of 2021 administrative costs are divided by the forecasted LRS kWh sales by customer group to arrive at three different factors. We find that NGrid's calculation of these charges appear to be supported by the data and should be approved.

TRANSITION CHARGE

NGrid is requesting changes to only the transition adjustment charge. The transition adjustment charge is used to account for prior under- or over-collection of these costs. For 2022, the adjustment charge is due

[1] Schedule NECO-3, p. 1.
[2] Company response to Division 1-1(a) in Docket No. 4805.
[3] Schedule NECO-4, p. 1.
[4] Schedule NECO-6, p. 1.
[5] Schedule NECO-6, p. 8.
[6] Schedule NECO-5, p. 1.
[7] Schedule NECO-5, p. 2-4.

to an under-recovery of charges in CY 2021. The transition adjustment charge is calculated by dividing the over-recovery balance from 2021 by the forecasted kWh deliveries during the recovery period, April 2022 through March 2023. This adjustment incorporates the final balance of over-recovery incurred in CY 2019.

The transition charge itself is a function of the contract termination charges ("CTC") billed to NGrid by New England Power Company ("NEP") and Montaup. The CTC charge is calculated by aggregating the individual CTC charges and dividing them by the total GWh deliveries, resulting in a weighted average base Transition Charge. The previous transition charge was a credit primarily because NEP and Montaup received net credits for actual nuclear decommissioning and other post shut-down costs, which were estimated to be zero starting in 2011. Connecticut Yankee, Maine Yankee, and Yankee Atomic (collectively referred to as "the Yankees") filed suit against the Department of Energy ("DOE") for its failure to remove the Yankees' respective spent nuclear fuel stores as required by law. So far, money has been awarded in four Phases, covering different time periods.[1] NEP and Montaup received proceeds for Phase I and Phase II of the litigation that were credited to customers between 2013 and 2015. No proceeds were returned by NEP and Montaup from October 1, 2015 through September 30, 2016.

According to the 2017 CTC Reconciliation Reports[2] filed by NGrid, in December of 2016 NEP received $5.9 million in proceeds and Montaup received $1.7 million in proceeds for Phase III litigation, which they planned to return to customers in the following year's CTC reconciliation. In the 2018 CTC Reconciliation Reports[3] filed by NGrid, Phase III litigation proceeds were received in December of 2016 by Montaup and NEP in the amounts of $3.2 million and $14.8 million, respectively, and were credited to customers through the 2017 CTC reconciliation filed in January 2018.[4] NGrid did not receive excess proceeds from NEP[5] or Montaup[6] to return to customers from October 1, 2017 through September 30, 2018, but is returning $6.3 million for October through December 2018 for NEP and about $3.3 million in December 2018 for Montaup.[7,8] Reconciliation of estimated to actual deliveries were overestimated. However, the variance in deliveries was offset by the negative transition charges in 2019 and 2020 producing excess revenue aggregating approximately $1.1 million for NEP and approximately $0.55 million for Montaup.[9]

NGrid explained that the Phase III litigation proceeds described in the 2018 CTC Reconciliation Reports replaced the amounts originally provided in the 2017 CTC Reconciliation Reports.[10] The discrepancy between the 2017 and 2018 Phase III litigation proceeds for Montaup and NEP was due to changes in how Connecticut Yankee and Maine Yankee handled the proceeds. Connecticut Yankee received $32.6 million

[1] In May 2017, Phase IV of the litigation was filed by the Yankees to cover 2013-2016.
[2] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2017.
[3] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2018.
[4] Company response to Division 1-6(b), p. 3, in Docket 4930.
[5] Narragansett has a 22.4% share of the NEP proceeds.
[6] Blackstone and Newport have shares of 29.13% and 11.85%, respectively.
[7] Company response to Division 1-6(b), Attachment DIV 1-6-1, p. 10 and 14, in Docket 4930.
[8] Company response to Division 1-6(b), Attachment DIV 1-6-2, p. 7, 10, and 11, in Docket 4930.
[9] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2021.
[10] Company response to Division 1-4 in Docket 4805.

of litigation proceeds instead of $34.6 million and the company only returned $18.4 million to wholesale customers instead of the entire amount, as originally intended.[1] The Company deposited $0.6 million of proceeds in its irrevocable external trust to fund Post Retirement Benefits Other Than Pension (PBOP), used $0.4 million of proceeds to pay the associated taxes, and deposited the remaining proceeds into the Decommissioning Trust Fund to fund long-term Independent Spent Fuel Storage Installation (ISFSI) operations and decommissioning costs.[2] Maine Yankee was awarded $24.6 million in damages, of which $3.6 million were returned to the Company's wholesale customers in December 2016, and remaining proceeds were deposited into the Decommissioning Trust Fund.[3] Yankee Atomic was awarded $19.6 million, all of which was deposited in the Decommissioning Trust Fund.[4]

Phase IV proceeds have been initially awarded in the amounts of $40.7 million to Connecticut Yankee, $28.1 million to Yankee Atomic, and $34.4 million to Maine Yankee, followed by an additional $500,000 in June 2019, for Phase IV, covering the period of 2013 to 2016. The Yankees plan to file Phase V, covering 2017 to 2020, in late spring 2021.[5]

The Company is not proposing a base transition charge in this filing. The PUC directed the Company to submit a Non-Bypassable Transition Charge Adjustment Provision providing that CTC credits billed to the Company be credited to the Company's Storm Fund.[6] The proposed Transition Adjustment Factor Charge is 0.018 cents/kWh[7], the under-recovery balance is divided by the forecasted kWh deliveries for the April 1, 2022 through March 31, 2023 period.[8]

Overall, we find that the transition adjustment charge to be consistent with the underlying data presented and the Company's tariff. We recommend that the charge be approved.

TRANSMISSION SERVICE CHARGE

The Company has estimated its 2022 costs for transmission service to be $232.6 million.[9] Table 1 below provides a summary of this estimate and compares it to previous estimates used to establish transmission service charges in the two previous years. The forecasted transmission costs from 2020 to 2021 increased by $21.7million (11%), while the 2022 projected value increases the transmission costs by $10.5 million (5%) relative to the 2021 transmission cost forecast.

[1] Company response to Division 1-4 in Docket 4805.
[2] Company response to Division 1-6(b), p. 2, in Docket 4930.
[3] Company response to Division 1-6(b), p. 2, in Docket 4930.
[4] Company response to Division 1-6(b), p. 2, in Docket 4930.
[5] Reconciliation of Contract Termination Charge to the Narragansett Electric Company and Reconciliation of Contract Termination Charge to Blackstone Valley Electric Company and Newport Electric Corporation, each submitted in January 2020.
[6] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p. 23, lines 6-10.
[7] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p. 24, line 15.
[8] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p. 24, lines 16-18.
[9] Testimony of Gallagher, Briggs, Oliveira, Ahirrao, p.36, line 19.

Ln #	Item		Feb-20	Feb-21	Incr/(Decr)	Feb-22	Incr/(Decr)	% Change
	NEP Local Charges							
1	Non-PTF Demand Charges		$ 35,745,041	$ 39,136,736	$ 3,391,695	$ 42,177,829	$ 3,041,093	8%
2	Other NEP Charges		$ 446,593	$ 475,734	$ 29,141	$ 402,851	$ (72,883)	-15%
3	BITS Surcharge		$ 18,961,716	$ 21,454,006	$ 2,492,290	$ 10,521,889	$ (10,932,117)	-51%
4		*Subtotal*	$ 55,153,350	$ 61,066,476	$ 5,913,126	$ 53,102,569	$ (7,963,907)	-13%
	ISO-NE Regional Charges							
5	PTF Demand Charge		$ 138,120,231	$ 153,493,464	$ 15,373,233	$ 170,843,952	$ 17,350,488	11%
6	Scheduling & Dispatch		$ 1,856,498	$ 1,952,294	$ 95,796	$ 2,221,149	$ 268,855	14%
7	Black Start		$ 1,307,372	$ 1,718,686	$ 411,314	$ 2,146,679	$ 427,993	25%
8	Reactive Power		$ 1,184,217	$ 1,206,744	$ 22,527	$ 1,262,382	$ 55,638	5%
9		*Subtotal*	$ 142,468,318	$ 158,371,188	$ 15,902,870	$ 176,474,162	$ 18,102,974	11%
	ISO-NE Administrative Charges							
10	Schedule 1 - Scheduling & Dispatch		$ 2,443,976	$ 2,457,933	$ 13,957	$ 2,824,067	$ 366,134	15%
11	Schedule 3 - Reliability Admin. Service		$ 208,627	$ 111,038	$ (97,589)	$ 79,412	$ (31,626)	-28%
12	Schedule 5 - NESCOE		$ 123,314	$ 84,029	$ (39,285)	$ 104,985	$ 20,956	25%
13		*Subtotal*	$ 2,775,917	$ 2,653,000	$ (122,917)	$ 3,008,464	$ 355,464	13%
14		**Total**	**$ 200,397,585**	**$ 222,090,664**	**$ 21,693,079**	**$ 232,585,195**	**$ 10,494,532**	**5%**

Table 1. Summary of 2020-2022 Transmission Costs

As seen in the Incr/(Decr) column in Table 1, of the approximate $10.5 million increase, the primary cost driver is an increase of about $17.3 million for the forecasted Pooled Transmission Facility ("PTF") demand charges, along with an increase of $3.0 million in Non-PTF demand charges. While the previously mentioned categories are cost drivers for the overall total increase in charges, a decrease of $10.9 million in the BITS surcharge is the main driver that results in a less significant increase (5%) in total charges as compared to $21.7 million in 2021. There is a small decrease in the ISO-NE Reliability Admin service charge.

The increase in the PTF demand charge comes from ISO-NE. These are for PTFs that receive regional funding support. PTF charges fluctuate yearly based on the projects that are approved by ISO-NE. The increase in PTF demand charges is primarily driven by a decrease in forecasted NRP charges of $7.96 million offsetting an increase of $18.1 million in forecasted ISO-NE PTF Demand Charges. The ISO-NE PTF Demand Charge increase is a result of a 6% increase in the Company's Regional Network Load as well as an increase of 5.12% in Regional Network Service (RNS).[1]

The increase in estimated Non-PTF Demand charges results from a higher estimated Non-PTF revenue requirement, as compared to the previous years.[2] This change in revenue requirement is based on an updated formula rate calculation that calculates the Non-PTF revenue requirement on an annual basis and sets the LNS rate using annual LNS load for the most recently available calendar year. The actual monthly charge will be calculated by multiplying the actual monthly Non-PTF load by the LNS rate.[3] As shown in the tables above, the BITS Surcharge is another NEP charge to NGrid, put into effect on November 1, 2016. This surcharge was approved by the FERC, under Schedule-21 of the ISO/RTO Tariff, to recover the Company's share of the costs for the Block Island Cable and associated facilities linked with the Town of

[1] Testimony of Alexei Spinu p. 23, lines, 10-15
[2] Testimony of Alexei Spinu p. 23, lines, 18-19
[3] Company response to PUC 1-15, Attachment 1-15

New Shoreham Project. This project is a public policy undertaking that allowed for the construction of a small-scale offshore wind demonstration project off the coast of Block Island. Annual costs of these facilities are recovered through a reconciling rate adjustment from NGrid's customers and/or from the Block Island Power Company (BIPCo). The BITS Surcharge allocation to NGrid is calculated based on an amended formula that equals 1/12th of the product of the integrated facilities credit paid to the Company under NEP's FERC Electric Tariff No. 1 (IFA Facilities Credit), updated around June each year, multiplied by NGrid's Load Share Percentage (one (1) less BIPCo's Load Share Percentage based on the prior year's load data).[1] Costs are then passed through to retail customers under the Transmission Service Cost Adjustment. In this forecast, the estimated BITS Surcharge to Narragansett for April 2022 through March 2023 is about $10.9 million less than last year's filing. This is due to the proposed change in formula rate that now incorporates actual expenses.[2]

Schedule NECO-11 provides the estimated annual surcharge calculation, which is passed through to customers under the Transmission Service Cost Adjustment.

The Company proposes to recover the estimated 2022 costs via demand and energy charges, as appropriate for each rate class. Schedule NECO-11 provides the details of this allocation. The allocators used to assign estimated transmission costs to each rate class are a weighted average of energy use for 12 months ending 12/31/2008, 12 months ending 12/31/2011 and 12 months ending 6/30/2017 (Test Year used in the Company's recent rate case – Docket 4770), as these are years with relatively normal weather. The use of more recent years to develop the allocators was ordered by the PUC in Docket 4805 based on our recommendation.

Based upon the above discussion, we find the Company's forecast of 2022 transmission cost and the rates designed to recover that amount to be reasonable. We recommend that the Commission approve the charge.

TRANSMISSION SERVICE RECONCILIATION

The previous year's forecast of transmission service charges is reconciled against 2021 actual transmission service revenues and expenses. Schedules NECO-12 and NECO-13 provide the basis for this reconciliation. As of the beginning of 2021, the cumulative variance between revenues and expenses, not including interest, is an over-collection of $4,824,824 as calculated in NECO-12. The Company will refund this over-collection over the period of April 1, 2021 through March 31, 2022. Additional interest during this period is estimated by the Company to be $30,701, which brings the total to be refunded to $4,855,525.[3] The beginning balance for January 2021 was $765,667 which was a "true-up" of the estimated December 2020 transmission expenses from Docket 5127 with the actual December 2020 expenses.[4] This year the Schedule NECO-13 determines the cents/kWh rate for each customer class that will be refunded or

[1] Testimony of Alexei Spinu p. 14, lines, 1-7.
[2] Testimony of Alexei Spinu p. 23-24, lines 20-21 and line 1.
[3] Schedule NECO-12, p. 1, lines 16-18.
[4] Testimony of Gallagher, Briggs, Oliveira, and Ahirrao p. 29-30, lines 16-19 and 1-3.

charged to the respective class's share of the over/under-collection. Using a representative sample analysis, we find the calculations in Schedule NECO-13 to be accurate.

We find the Company's 2022 transmission reconciliation over-recovery and the rates designed to refund that amount to be reasonable and recommend that they be approved.

TRANSMISSION-RELATED UNCOLLECTIBLE EXPENSE

The Company's Transmission Service Cost Adjustment Provision ("TSCAP") allows it to collect from customers an estimate of transmission-related uncollectible accounts receivable, currently equal to 1.30% of the estimated amount of transmission costs to be incurred during 2022. Schedule NECO-14 provides the calculation of this amount. The TSCAP also requires the Company to reconcile its forecast of the transmission-related uncollectible accounts receivable for 2021. This reconciliation occurs only for actual 2021 revenue. Schedule NECO-15 provides these reconciliation calculations. We note that the reconciliation calculations in Schedule NECO-15 for 2021 used a weighted uncollectible factor of 1.30%. Using a representative sample analysis, we find the calculations in Schedule NECO-14 and NECO-15 to be accurate and recommend that the rates contained therein be approved.

NET METERING CHARGE

The net metering charge recovers the costs of renewable net metering credits and payments to qualifying facilities in excess of payments the Company receives from ISO-NE for the sale of this energy in the market. The Company is proposing a Net Metering charge change to 0.488 cents/kWh[1] from 0.436 cents/kWh. The net metering charge including adjustments for 2021 was $36,032,809.[2] This is an increase from $30,557,074 from 2020[3]. NGrid's calculation of this charge appears to be supported by the data and should be approved.

It is our understanding that the Commission will establish a separate proceeding to address several issues related to net metering, including determining how the excess production of power will be handled for individual accounts. Therefore, we postpone providing comments in connection with those issues until the appropriate time.

LONG-TERM CONTRACTING FOR RENEWABLE ENERGY RECOVERY RECONCILIATION FACTOR

The current base Long-Term Contracting for Renewable Energy Recovery ("LTCRER") is a 0.167 cents/kWh charge. NGrid proposes to credit this by subtracting the LTCRER Reconciliation Factor of 0.123 cents/kWh,[4] bringing the net LTCRER to 0.044 cents/kWh starting April 1, 2022 through June 30, 2022. The LTCRER Reconciliation Factor is used to collect (or refund) any under- (or over-) recovery of Long-Term Contracting

[1] Schedule NECO-16, p. 1.
[2] Schedule NECO-16, p. 1
[3] Schedule NECO-16, p. 3
[4] Schedule NECO-18, p. 1.

expenses. For 2021, NGrid reports an over-recovery of approximately $9.1 million (with interest).[1] The over-recovery amount is net of REC proceeds from RECs purchased through long-term contracts for renewable energy. To estimate the REC proceeds, NGrid must calculate a transfer price. NGrid provided the transfer price in its workpapers, and it appears to be reasonable. Note, this factor will terminate on June 30, 2022 and a new factor will take its place for contracts July 1, 2022 to December 31, 2022. The over-recovery balance reflects an adjustment of $474,810 shown in April 2021.[2] This adjustment represents an over-recovered balance of the over-recovery incurred during 2020 and credited to customers during the period ending March 31, 2022. NGrid's calculation of the LTCRER Reconciliation Factor appears to be supported by the data provided and is in accordance with R.I.P.U.C. No. 4673. The proposed rate should be approved.

[1] Schedule NECO-18, p. 1.
[2] Schedule NECO-18, p. 1.