DAYMARK ENERGY ADVISORS

To: RHODE ISLAND PUBLIC UTILITIES COMMISSION

From: Carrie Gilbert and Aliea Afnan, DAYMARK ENERGY ADVISORS

Date: March 17, 2020

Subject: 2020 Retail Rates Filing – Docket No. 5005

INTRODUCTION

On February 14, 2020, National Grid (NGrid or the Company) filed its 2020 Retail Rate Filing. This filing consists of rate adjustments arising out of the reconciliation of the Company's Standard Offer Service (SOS), SOS 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 2019 through December 2019. The proposed rate adjustments are effective for usage on and after April 1, 2020. The net effect of all proposed rate changes for a typical residential SOS customer is a 1.8% increase. Based on the Public Utility Commission's (PUC's) Orders in Dockets 4599 and 4691, the Company has provided Excel files of its workpapers supporting the 2020 Annual Retail Rates Filing. This filing was designated as Docket No. 5005.

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. However, we make the following recommendation:

- Regarding the Transmission Service Reconciliation, the Company should use actual December 2019 expenses in place of the estimated expenses, if they are available, before adjusting rates April 1, 2020.

This memorandum presents the full results of our review.

STANDARD OFFER SERVICE ADJUSTMENT FACTORS

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

For the first charge, the SOS reconciliation adjustment, the filing at Schedule REP-2, p. 1, shows a net over-recovery (with interest) of approximately $5 million in calendar year (CY) 2019, compared to the over-recovery (with interest) of approximately $3.7 million in CY 2018. This CY 2019 total is a sum of the separately-calculated totals for each of the three SOS customer groups: Residential, Commercial, and Industrial. These totals are then adjusted for additional interest during the recovery period and divided by forecasted customer group SOS kWh sales for April 2020 through March 2021 to calculate three different adjustment factors, one for each procurement group. The Residential group had an over-recovery (with interest) of approximately $7.6 million. The Commercial and Industrial groups had under-recoveries (with interest) of $0.9 million and $1.7 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 SOS rates beginning in April 2019.[2] These calculations show that there was an over recovery of capacity costs for residential customers of $715K and an under-recovery for commercial and industrial customers of $851k and $562k respectively.[3] According to the Testimony of Ms. Pieri and her response to Division Data Request 2-1, these costs are inherently included in the over/under-recovery balance of the Standard Offer Service base reconciliation shown on pages 2-4 of Schedule REP-2 and contribute to the total over or under recovery for each class.

The SOS reconciliation adjustment for CY 2020 includes the additional following adjustments: $279,469 reflecting the remaining balance of CY 2017 net over-recovery SOS expenses; and increased the SOS reconciliation by $218,926 for unbilled SOS Billing Adjustments for CY 2019. The net unbilled billing adjustment revenue for CY 2019 is the combination of a positive $220,262[4] for Residential and a negative

[1] Schedule REP-2, pages 2, 3, and 4.

[2] Testimony of Robin E. Pieri, p. 7, lines 18-21.

[3] Schedule REP-2, page 7.

[4] Schedule REP-2, page 2.

$1,336[5] for Commercial SOS customers. These amounts equate to a debit or revenue shortfall of $60,543[6] which means the Company paid more for the SOS supply of customers than it billed to the customers that left SOS and took electric supply from a third party.[7] NGrid is proposing this amount as an adjustment to the Revenue Decoupling Mechanism (RDM)[8] reconciliation, which will be filed by May 15, 2020.[9] Through the RDM Adjustment Factor, all customers will be assessed a portion of the net SOS Billing Adjustment debit.

On a per kWh basis, the charge with the largest magnitude SOS adjustment is a 0.381 cents/kWh credit for the Industrial class. This is compared to a 2019 CY charge of 0.138 cents/kWh.[10] According to Schedule REP-3 page 2, there is a 58% increase in the projected Industrial class kWh sales despite a 4% decrease in the total Industrial class demand. This is because the proportion of Industrial class sales served by SOS has increased from 11.99% to 19.76%. In response to Division Data Request 2-2, the Company stated that the number of Industrial customers served by SOS has decreased slightly from 265 in 2018 to 261 in 2019. The Company also stated that the percent of Industrial demand served by SOS demand varies throughout the year, and 19.76% was at the high end of the range, but that they have traditionally used the more recent month's data to calculated estimate SOS kWh for the upcoming year.

The SOS adjustment for the Residential class is a credit of 0.294 cents/kWh compared to a credit of 0.223 cents/kWh last year. The Commercial class will be charged 0.094 cents/kWh compared to a charge of 0.154 cents/kWh last year.[11] When asked in Docket 4805 about the swings in net over- and under-recovery to the different SOS 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 SOS retail rates are estimated and may vary from actual line losses; (3) estimated spot market prices are used to develop the retail SOS rates and actual spot market prices may differ; and (4) customers are billed on a billing cycle basis while the Company is billed for SOS expenses on a calendar month basis.[12] Our review indicates the SOS reconciliation adjustment factors are consistent with the underlying data and tariff R.I.P.U.C. No. 2113 and are reasonable.

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[5] Schedule REP-2, page 3.

[6] Schedule REP-2, page 1.

[7] Testimony of Robin E. Pieri, p. 16, line 18 to p. 17, line 6.lines 8-17.

[8] The RDM Adjustment Factor is a uniform per kWh factor applicable to all retail delivery service customers.

[9] Testimony of Robin E. Pieri, p. 19, lines 1-3.

[10] Schedule REP-3, page 1.

[11] Schedule REP-3, page 1.

[12] Company response to Division 1-1(a) in Docket No. 4805.

The Administrative Cost Factor includes an allowance for SOS uncollectible expense and several administrative cost elements (chief of which is cash working capital). The 2020 filing shows total administrative expense of approximately $7.5 million[13] compared to approximately $7.5 million in the 2019 filing. Uncollectible expense is lower than last year despite the large projected increase in the Industrial class demand due to lower projected SOS rates for all three classes.[14] The cash working capital requirement is $40.3 million[15], compared to $32.9 million in the 2019 filing. This increase was mostly due to an increase in the customer payment lag from an average of 51 days in 2019 to 64 days[16] in 2020.

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

SOS Administrative Cost Reconciliation Adjustment Factor is based upon the over- or under-collection of administrative costs for the prior year. For the 2020 filing, the Company reports a net under-collection of 2019 administrative costs of approximately $1.6 million (with interest).[17] The Residential, Commercial, and Industrial customer groups showed under-collections of $1,032,721, $463,603, and $84,129 respectively.[18] 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 over-collection of 2019 administrative costs are divided by the forecast SOS kWh sales by customer group to arrive at three different factors. We find NGrid's calculation of these charges appears to be supported by the data and should be approved.

TRANSITION CHARGE

NGrid is requesting changes to both the transition charge and transition adjustment charge, which is used to account for prior under- or over-collection of these costs. For 2020, the adjustment charge is due to an over-recovery of charges in CY 2019. The transition adjustment charge is calculated by dividing the over-recovery balance from 2019 by the forecasted kWh deliveries during the recovery period, April

[13] Schedule REP-4, p. 1.
[14] Schedule REP-4, p.2.
[15] Schedule REP-6, p. 1.
[16] Schedule REP-6, page 7.
[17] Schedule REP-5, p. 1.
[18] Schedule REP-5, pp. 2-4.

2020 through March 2021. This adjustment incorporates the final balance of over-recovery incurred in CY 2017.

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 three Phases, covering different time periods.[19] 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[20] 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[21] 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.[22] NGrid did not receive excess proceeds from NEP[23] or Montaup[24] 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.[25,26] 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.[27] The discrepancy between the 2017 and 2018 Phase III litigation proceeds for Montaup and

[19] In May 2017, Phase IV of the litigation was filed by the Yankees to cover 2013-2016.

[20] 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.

[21] 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.

[22] Company response to Division 1-6(b), p. 3, in Docket 4930.

[23] Narragansett has a 22.4% share of the NEP proceeds.

[24] Blackstone and Newport have shares of 29.13% and 11.85%, respectively.

[25] Company response to Division 1-6(b), Attachment DIV 1-6-1, pp. 10 and 14, in Docket 4930.

[26] Company response to Division 1-6(b), Attachment DIV 1-6-2, pp. 7, 10, and 11, in Docket 4930.

[27] Company response to Division 1-4 in Docket 4805.

NEP was due to changes in how Connecticut Yankee and Maine Yankee handled the proceeds. Connecticut Yankee received $32.6 million 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. 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.[28] 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.[29] Yankee Atomic was awarded $19.6 million, all of which was deposited in the Decommissioning Trust Fund.[30]

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.[31]

The base transition charge credit factor for the upcoming year is 0.074 cents/kWh. When combined with the transition charge adjustment factor credit of 0.008 cents/kWh, the proposed total transition charge credit factor is 0.082 cents/kWh.[32] The change in the transition charge compared to last year's filing is primarily due to the changes in credits returned to customers during CY 2018.

Overall, we find the base transition charge credit to be consistent with the NEP charges reported in the NEP and Montaup CTC Reconciliation Reports. We also find that the adjustment factor charge credit to be consistent with the underlying data presented and the Company's tariff. We recommend that both charge credits be approved.

TRANSMISSION SERVICE CHARGE

The Company has estimated its 2020 costs for transmission service to be $200.4 million, as described by the testimony of Michael V. Artuso. 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

[28] Company response to Division 1-6(b), p. 2, in Docket 4930.

[29] Company response to Division 1-6(b), p. 2, in Docket 4930.

[30] Company response to Division 1-6(b), p. 2, in Docket 4930.

[31] 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.

[32] Revised Testimony of Robin E. Pieri, p. 20.

forecasted transmission costs from 2018 to 2019 decreased by $10.3 million (5%), while the 2020 projected value increases the transmission costs by $2.6 million (1%) relative to the 2019 transmission costs.

NARRAGANSET ELECTRIC COMPANY

SUMMARY OF TRANSMISSION COSTS

Ln #	Item		Feb-18	Feb-19	Incr/(Decr)	Feb-20	Incr/(Decr)	% Change
	NEP Local Charges							
1	Non-PTF Demand Charges		$ 32,871,310	$ 25,946,640	$ (6,924,670)	$ 35,745,041	$ 9,798,401	27%
2	Other NEP Charges		$ 273,453	$ 360,615	$ 87,162	$ 446,593	$ 85,978	19%
3	BITS Surcharge		$ 21,925,423	$ 20,272,480	$ (1,652,943)	$ 18,961,716	$ (1,310,764)	-7%
4		*Subtotal*	$ 55,070,186	$ 46,579,735	$ (8,490,451)	$ 55,153,350	$ 8,573,615	16%
	ISO-NE Regional Charges							
5	PTF Demand Charge		$ 145,847,743	$ 144,304,593	$ (1,543,150)	$ 138,120,231	$ (6,184,362)	-4%
6	Scheduling & Dispatch		$ 2,225,931	$ 1,971,263	$ (254,668)	$ 1,856,498	$ (114,765)	-6%
7	Black Start		$ 776,594	$ 877,984	$ 101,390	$ 1,307,372	$ 429,388	33%
8	Reactive Power		$ 1,249,058	$ 1,296,001	$ 46,943	$ 1,184,217	$ (111,784)	-9%
9		*Subtotal*	$ 150,099,326	$ 148,449,841	$ (1,649,485)	$ 142,468,318	$ (5,981,523)	-4%
	ISO-NE Administrative Charges							
10	Schedule 1 - Scheduling & Dispatch		$ 2,625,632	$ 2,461,473	$ (164,159)	$ 2,443,976	$ (17,497)	-1%
11	Schedule 3 - Reliability Admin. Service		$ 192,185	$ 201,233	$ 9,048	$ 208,627	$ 7,394	4%
12	Schedule 5 - NESCOE		$ 95,784	$ 105,915	$ 10,131	$ 123,314	$ 17,399	14%
13		*Subtotal*	$ 2,913,601	$ 2,768,621	$ (144,980)	$ 2,775,917	$ 7,296	0%
14		**Total**	**$ 208,083,113**	**$ 197,798,197**	**$ (10,284,916)**	**$ 200,397,585**	**$ 2,599,389**	**1%**

Table 1. Summary of 2018-2020 Transmission Costs

As seen in the Incr/(Decr) column in Table 1, of the approximate $2.6 million increase, an increase of about $8.6 million in the forecasted NEP local charges is the primary cost driver, which is offset by a decrease of about $6 million in the ISO-NE Regional and Administrative Charges.

NGrid explained that the decrease in the forecasted ISO-NE Regional Charges is primarily driven by a decrease in the Company's Regional Network Load, which is offset by an increase in the forecasted Regional Network Service (RNS) rate driving an overall increase.[33] The RNS rate of $119.51 kW-yr (June 1, 2020 through May 31, 2021) is comprised of the total RNS rate through May 31, 2020 ($11.94/kW-yr) plus the additional estimated ISO RNS rate ($7.57/kW-yr).[34] In Docket 4930, the RNS rate was $117.17/kW-yr for June 1, 2019 through May 31, 2020 where the total RNS rate through May 31, 2019 was $110.43/kW-yr and the additional estimated ISO RNS rate was $6.74/kW-yr.[35] The Company developed its projection of PTF costs from a presentation by the Pool Transmission Owners

[33] Testimony of Michael V. Artuso, p. 20.

[34] Schedule MVA-3, p. 1.

[35] Schedule MVA-3, p. 1

Administrative Committee (PTO AC) Rates Working Group's presentation to the New England Power Pool (NEPOOL) Reliability Committee/Transmission Committee. We have reviewed this presentation and find it to be a reasonable source for a 2020 rate for RNS.

The estimate of Non-PTF costs incorporates NGrid's estimates of Non-PTF plant additions.[36] These costs are estimated on a project-by-project basis. The Company provided the project-by-project costs by state.[37] The Non-PTF projects in 2020 for Massachusetts ($46.7 million), Rhode Island ($32.1 million), New Hampshire ($14.7 million), and Vermont ($0.6 million) total $94.1 million.[38] We have reviewed these estimates and find them to be reasonable.

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 New Shoreham Project. This project is a public policy undertaking that allows for the construction of a small-scale offshore wind demonstration project off the coast of Block Island. Annual costs of these facilities will be 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 by multiplying the integrated facilities credit received by the Company through NEP's FERC Electric Tariff No. 1 (IFA Facilities Credit), updated around June each year, by NGrid's Load Share Percentage (one (1) less BIPCo's Load Share Percentage based on the prior year's load data). Costs are then passed through to retail customers under the Transmission Service Cost Adjustment. In this forecast, the estimated BITS Surcharge to Narragansett for the April 2020 through March 2021, which is about $1.3 million lower than last year's filing, is based on the expected monthly gross plant investment balances times the current carrying charge times the allocation to Narragansett.

Schedule MVA-7 provides the estimated annual surcharge calculation, which is passed through to customers under the Transmission Service Cost Adjustment. The annual surcharge is subject to change based on the carrying charge, currently 16.63%, which is updated each year and was calculated using NGrid's CY 2018 FERC Form 1 data per the provisions of NEP's Electric Tariff No.1 (Line 14 note in Schedule MVA-7).

The Company proposes to recover the estimated 2020 costs via demand and energy charges, as appropriate for each rate class. Schedule REP-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

[36] Company provided a list of these additions to the Division through its response to Division 1-2 in Docket No. 5005.

[37] Company response to Division 1-2(b), Attachment DIV 1-2_B.

[38] The $94.1 million corresponds to Schedule MVA-6, p. 1, line 4.

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 2020 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 2019 actual transmission service revenues and expenses. Schedules REP-12 and REP-13 provide the basis for this reconciliation. As of the beginning of 2019, the cumulative variance between revenues and expenses, not including interest, is an over-collection of $14,428,219, as calculated in REP-12. The Company will refund this over-collection over the period of April 1, 2020 through March 31, 2021. Additional interest during this period is estimated by the Company to be $245,287, which brings the total to be refunded to $14,673,506. The beginning balance for January 2019 was $3,009,235, which was a "true-up" of the estimated December 2018 transmission expenses from Docket 4930 with the actual December 2018 expenses.[39] In discovery, the Company explained that transmission expenses in 2019 were $11.6 million lower than forecasted, due primarily to the Company's decrease in lower regional network service expense due to the Company's load in comparison to the forecast.[40] As calculated previously, regional rates are calculated annually effective June 1st of each year; NGrid's load was up 46% compared to the prior month and a slight increase in June's effective RNS rate resulted in higher expenses when compared to revenues.[41] This year the Schedule REP-13 determines the cents/kWh rate for each customer class that will be refunded or charged to the respective class' share of the over/under-collection. Using a representative sample analysis, we find the calculations in Schedule REP-13 to be accurate.

We find the Company's 2019 transmission reconciliation over-recovery and the rates designed to refund that amount to be reasonable and recommend that they be approved. However, we recommend that before adjusting rates April 1, 2019, the Company use actual December 2018 expenses in place of the estimated expenses, if they are available.

39 Revised Testimony of Robin E. Pieri, pp. 25-26.

40 Company response to Division 1-1(a) in Docket 5005.

41 Company response to Division 1-1(b) in Docket 5005.

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 2020. Schedule REP-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 2019. This reconciliation occurs only for actual 2019 revenue. Schedule REP-15 provides these reconciliation calculations. We note that the reconciliation calculations in Schedule REP-15 for 2019 used a weighted uncollectible factor of 1.30%. Using a representative sample analysis, we find the calculations in Schedule REP-14 and REP-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 0.266 cents/kWh[42] from 0.068 cents/kWh. In calculating the Net Metering reconciliation, the Company made an adjustment of $69,563 in April 2019 for the remaining unrecovered balance of the costs incurred during 2017 and recovered from customers during the period that ended March 31, 2019.[43] NGrid's calculation of this charge appears to be supported by the data and should be approved.

LONG-TERM CONTRACTING FOR RENEWABLE ENERGY RECOVERY RECONCILIATION FACTOR

The current base LTC Recovery Factor is a 0.481 cent/kWh charge. NGrid proposes to add to this an LTC Recovery Reconciliation Factor of 0.198 cent/kWh[44], in accordance with tariff R.I.P.U.C. No. 4673.[45] The LTC Recovery Reconciliation Factor is used to collect (or refund) any under- (or over-) recovery of LTC expenses. For 2019, NGrid reports an under-recovery of approximately $13.6 million (with interest) compared to $4.42 million (with interest) in 2018. The under-recovery amount is net of REC proceeds from RECs purchased through long-term contracts for renewable energy. To estimate the REC proceeds,

[42] Schedule REP-16, p. 1.

[43] Revised Testimony of Robin E. Pieri, pp. 36.

[44] Second Revised Schedule REP-18, p. 1.

[45] In response to Division 1-3(a), the Company explained that a September expense of $37,152.50 was removed from the reconciliation, because it was related to a consultant, and some employee labor cost, from bidding the capacity of the Renewable Growth Program's distributed generation units into the Forward Capacity Market during 2019, not related to bidding capacity of Long Term Contracting renewable energy resources. This expense will be included in the cost of the RE Growth Program's reconciliation in June 2020.

NGrid must calculate a transfer price. NGrid provided the transfer price in its workpapers, and it appears to be reasonable. The under-recovery balance reflects an adjustment of $19,280 shown in April 2019.[46] This adjustment represents the remaining unrecovered balance of the under-recovery incurred during 2017 and recovered from customers during the period ending March 31, 2019. NGrid's calculation of the Long-Term Contracting for Renewable Energy Recovery (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.

[46] Second Revised Schedule REP-18, p. 1.