STATE OF RHODE ISLAND

DIVISION OF PUBLIC UTILITIES & CARRIERS
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March 10, 2023

Ms. Luly Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, R.I. 02888

Re: Docket 23-03-EL Rhode Island Energy 2023 Retail Rate Filing

Dear Ms. Massaro:

On behalf of the Division of Public Utilities & Carriers, please accept the attached memorandum, authored by Carrie Gilbert and Aliea Afnan Munger of Daymark Energy Advisors, which provides the Division's comments regarding the above referenced docket.

Very Truly Yours,

Margaret L. Hogan, Esq. (#5006)

Enclosure

cc: 23-03-EL Service List
Linda D. George, Esq., Administrator
John Spirito, Esq., Deputy Administrator
Christy Heatherington, Esq., Chief Legal Counsel
Paul Roberti, Esq., Chief Economic & Policy Analyst

DAYMARK ENERGY ADVISORS

MEMORANDUM

To: RHODE ISLAND PUBLIC UTILITIES COMMISSION

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

Date: March 10, 2023

Subject: Rhode Island Energy 2023 Retail Electric Rate Filing – Docket No. 23-03-EL

INTRODUCTION

On February 15, 2023, Rhode Island Energy[1] ("RI Energy" or "the Company") filed its 2023 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 2022 through December 2022. The proposed rate adjustments are effective for usage on and after April 1, 2023. The net effect of all proposed rate changes for a residential LRS customer using 500/kWh per month is an increase of $5.07 or 3.4%. Based on the Rhode Island Public Utilities Commission's (PUC's) Orders in Dockets 4599 and 4691, the Company has provided Excel files of its workpapers supporting the 2023 Annual Retail Rates Filing. This filing was designated as Docket No. 23-03-EL.

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. This review has identified one issue that should be addressed as soon as possible:

1. For the LRS reconciliation, it is unclear how the calculations on Schedule NECO-2 regarding Capacity Risk Premium and Estimated & Actual Capacity flow through to the LRS reconciliation. We would like to clarify this issue prior to making a final recommendation on this billing factor.

The Division will consult further with the Company on this issue prior to the scheduled hearing.

We find that that RI Energy calculated all the other charges appropriately based on the underlying data the Company presented and the Company's tariff. We do have the following recommendation:

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[1] The sale of National Grid Rhode Island to PPL, and now referred to as Rhode Island Energy, was finalized on May 25, 2022

\$3,060.[1] The Company is proposing to recover the remaining LRS reconciliation balance from all customers.[2]

On a per kWh basis, the charge with the largest magnitude LRS adjustment is a 0.334 cents/kWh charge for the Residential class.[3] This is compared to a CY 2021 credit of 0.318 cents/kWh. The LRS adjustment for the Commercial class is a charge of 0.265 cents/kWh compared to a charge of 0.665 cents/kWh last year. The Industrial class will be charged 0.132 cents/kWh compared to a charge of 0.375 cents/kWh last year.[4] 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.[5] 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 2023 filing shows total administrative expense of approximately \$9.77 million[6] compared to approximately \$8.47 million in the 2022 filing. The cash working capital requirement is \$61.5 million[7], compared to \$48.1 million in the 2022 filing.

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 2023 filing, the Company reports a net under-collection of 2022 administrative costs of approximately \$3.0 million (with interest).[8] The Residential, Commercial, and Industrial customer groups showed under-collections of \$1,842,451, \$793,961, and \$412,186 respectively.[9] This net under-collection is largely due to a combination of higher expenses than revenues for all three customer groups.

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[1] Schedule NECO-8, p. 1.
[2] Testimony of Blazunas, Souza, Oliveira, Salk, p. 20, lines 16-17.
[3] Schedule NECO-3, p. 1.
[4] Schedule NECO-3, p. 1.
[5] Company response to Division 1-1(a) in Docket No. 4805.
[6] Schedule NECO-4, p. 1.
[7] Schedule NECO-6, p. 1.
[8] Schedule NECO-5, p. 1.
[9] Schedule NECO-5, p. 2-4.

Both the estimated administrative costs and under-collection of 2022 administrative costs are divided by the forecasted LRS kWh sales by customer group to arrive at three different factors. We are not comfortable with the uncertainty regarding the mechanics of the capacity costs calculations described above. We request that the Company provide a more thorough explanation prior to making a recommendation on this item.

TRANSITION CHARGE

RI Energy 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 2023, the adjustment charge is due to an under-recovery of charges in CY 2022. The transition adjustment charge is calculated by dividing the over-recovery balance from 2022 by the forecasted kWh deliveries during the recovery period, April 2023 through March 2024. This adjustment incorporates the final balance of under-recovery incurred in CY 2020.

The Transition Charge itself is a function of the contract termination charges ("CTC") billed to Rhode Island Energy by New England Power Company ("NEP") and Montaup. The CTC is calculated by aggregating the individual CTCs 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]

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."[2] The proposed Transition Adjustment Factor Charge is 0.021 cents/kWh[3], the under-recovery balance is divided by the forecasted kWh deliveries for the April 1, 2023 through March 31, 2024 period.[4]

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 2023 costs for transmission service to be $210.1 million.[5] 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 2021 to 2022 increased

[1] In May 2017, Phase IV of the litigation was filed by the Yankees to cover 2013-2016.
[2] Testimony of Blazunas, Souza, Oliveira, Salk, p. 21, lines 16-17.
[3] Testimony of Blazunas, Souza, Oliveira, Salk, p. 23, line 11.
[4] Testimony of Blazunas, Souza, Oliveira, Salk, p. 23, lines 13-14.
[5] Testimony of Blazunas, Souza, Oliveira and Salk, p.25, line 12.

by $16.8 million (7.5%), while the 2023 projected value decreases the transmission costs by $28.8 million (-12%) relative to the 2022 transmission cost forecast.

Ln #	Item		Feb-21	Feb-22	Incr/(Decr)	Feb-23	Incr/(Decr)	% Change
	NEP Local Charges							
1	Non-PTF Demand Charges		$ 39,136,736	$ 43,568,259	$ 4,431,523	$ 28,302,440	$ (15,265,819)	-35%
2	Other NEP Charges		$ 475,734	$ 415,157	$ (60,577)	$ 1,303,242	$ 888,085	214%
3	BITS Surcharge		$ 21,454,006	$ 10,521,889	$ (10,932,117)	$ 9,832,684	$ (689,205)	-7%
4		*Subtotal*	$ 61,066,476	$ 54,505,305	$ (6,561,171)	$ 39,438,366	$ (15,066,939)	-28%
	ISO-NE Regional Charges							
5	PTF Demand Charge		$ 153,493,464	$ 175,777,000	$ 22,283,536	$ 162,535,111	$ (13,241,889)	-8%
6	Scheduling & Dispatch		$ 1,952,294	$ 2,221,149	$ 268,855	$ 1,999,716	$ (221,433)	-10%
7	Black Start		$ 1,718,686	$ 2,146,679	$ 427,993	$ 2,126,081	$ (20,598)	-1%
8	Reactive Power		$ 1,206,744	$ 1,262,382	$ 55,638	$ 1,127,765	$ (134,617)	-11%
9		*Subtotal*	$ 158,371,188	$ 181,407,210	$ 23,036,022	$ 167,788,673	$ (13,618,537)	-8%
	ISO-NE Administrative Charges							
10	Schedule 1 - Scheduling & Dispatch		$ 2,457,933	$ 2,824,067	$ 366,134	$ 2,676,068	$ (147,999)	-5%
11	Schedule 3 - Reliability Admin. Service		$ 111,038	$ 79,412	$ (31,626)	$ 105,073	$ 25,661	32%
12	Schedule 5 - NESCOE		$ 84,029	$ 104,985	$ 20,956	$ 96,059	$ (8,926)	-9%
13		*Subtotal*	$ 2,653,000	$ 3,008,464	$ 355,464	$ 2,877,200	$ (131,264)	-4%
14		Total	**$ 222,090,664**	**$ 238,920,979**	**$ 16,830,315**	**$ 210,104,239**	**$ (28,816,739)**	**-12%**

Table 1. Summary of 2021-2023 Transmission Costs

As seen in the Incr/(Decr) column in Table 1, of the approximate $28.8 million decrease, the primary cost driver is a decrease of about $15.3 million for the forecasted Non-Pooled Transmission Facility ("Non-PTF") demand charges, along with a decrease of $13.2 million in PTF demand charges. While the previously mentioned categories are cost drivers for the overall decrease in charges, all but two categories also decrease leaving Other NEP and the Reliability Admin. Service charges as the only categories with an increase as compared to 2022.

The decrease 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 decrease in PTF demand charges is primarily driven by a decrease in load by 972,894 kW and the forecasted Regional Network Service (RNS) rates.[1] Load changes resulted in a $11.6 million decrease with RNS rates resulting in the remaining $1.6 million, totaling a $15.3 million decrease in Non-PTF Demand Charge.

The decrease in estimated Non-PTF demand charges results from a decrease in non-PTF related load by 702,387 kW in total. Whole load contributed to part of the decrease, the main driver is the decrease in the Local Network Service (LNS) rate used to calculate non-PTF charges.[2] The reason for the LNS rate change is due to RI Energy becoming an independent entity and is now calculated based on RI Energy's transmission revenue requirement and LNS load.[3]

[1] Testimony of Alexei Spinu, p. 26, lines 8-14
[2] Testimony of Alexei Spinu, p. 25, lines 11-17
[3] Testimony of Alexei Spinu, p. 25, lines 18-19

As shown in the tables above, the BITS Surcharge is another NEP charge to RI Energy, 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 allowed for the construction of a small-scale offshore wind power demonstration project off the coast of Block Island. Annual costs of these facilities are recovered through a reconciling rate adjustment from RI Energy's customers and/or from the Block Island Power Company (BIPCo). As of January 1, 2023, the BITS Surcharge allocation to RI Energy is calculated based on an amended formula that equals the Facilities charge for the BITS facilities multiplied by the Narragansett Electric Company's Load Share Percentage. The Load Share Percentage is calculated as one (1) less BIPCo's Load Share Percentage based on the prior year's load data.[1] The Facilities charge is the sum of several components including, BITS Gross Plant Investment multiplied by the Annual Distribution Facilities Carrying Charge, actual BITS Municipal Tax Expense, Actual BITS Operation and Maintenance Expense and 2.5% of the Total Primary Related Administrative and General Expense and is set to be updated annually around June each year.[2] Beginning January 1, 2023, The Narragansett Electric Company and BIPCo will be charged the BITS surcharge as calculated by RI Energy that are passed through to retail customers under the Transmission Service Cost Adjustment.[3] In this forecast, the estimated BITS Surcharge to Narragansett for April 2023 through March 2024, $0.69 million less than last year's filing.

Schedule NECO-10 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 2023 costs via demand and energy charges, as appropriate for each rate class. Schedule NECO-10 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. However, since Docket 4805, the Company has added to the data set the 12 months ending 6/30/2017 in these last five years.[4] We would like to restate that the Company should consider using a more recent set of years to develop the allocators for assigning transmission costs to each rate class.

Based upon the above discussion, we find the Company's forecast of 2023 transmission cost and the rates designed to recover that amount to be reasonable. We recommend that the Commission approve the charge.

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[1] Testimony of Alexei Spinu, p. 16, lines 9-13
[2] Testimony of Alexei Spinu, p. 16, lines 1-7
[3] Testimony of Alexei Spinu, p. 16, lines 19-21
[4] Company response to Division 1-9

TRANSMISSION SERVICE RECONCILIATION

The previous year's forecast of transmission service charges is reconciled against 2022 actual transmission service revenues and expenses. Schedules NECO-11 and NECO-12 provide the basis for this reconciliation. As of the beginning of 2023, the cumulative variance between revenues and expenses, not including interest, is an over-collection of $6,299,217 as calculated in NECO-11. The Company will refund this over-collection over the period of April 1, 2023 through March 31, 2024. Additional interest during this period is estimated by the Company to be $15,866, which brings the total to be refunded to $6,315,083.[1] The beginning balance for January 2022 was $3,960,300 which was a "true-up" of the estimated December 2021 transmission expenses from Docket 5234 with the actual December 2021 expenses.[2] This year the Schedule NECO-12 determines the cents/kWh rate for each customer class that will be refunded or charged to the respective class's share of the over/under-collection. Using a representative sample analysis, we find the calculations in Schedule NECO-12 to be accurate.

We find the Company's 2023 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 2023. Schedule NECO-13 provides the calculation of this amount. The TSCAP also requires the Company to reconcile its forecast of the transmission-related uncollectible accounts receivable for 2022. This reconciliation occurs only for actual 2022 revenue. Schedule NECO-14 provides these reconciliation calculations. We note that the reconciliation calculations in Schedule NECO-14 for 2022 used a weighted uncollectible factor of 1.30%. Using a representative sample analysis, we find the calculations in Schedule NECO-13 and NECO-14 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 0.628 cents/kWh[3] from 0.488 cents/kWh. The net metering charge including adjustments for 2022 was $46,070,988.[4] This is an increase from $36,032,809 from 2021[5]. RI Energy's calculation of this charge appears to be supported by the data and should be approved, but could change as the result of its filing in Docket No. 23-05-EL.

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[1] Schedule NECO-11, p. 1, lines 16-18.
[2] Testimony of Blazunas, Souza, Oliveira, and Salk, p. 28, lines 9-15.
[3] Schedule NECO-15, p. 1.
[4] Schedule NECO-15, p. 1
[5] Schedule NECO-15, p. 3

RI Energy has filed a proposal for handling excess net metering credits in Docket No. 23-05-EL. We will hold comments on that issue at this time.

LONG-TERM CONTRACTING FOR RENEWABLE ENERGY RECOVERY RECONCILIATION FACTOR

The current base Long-Term Contracting for Renewable Energy Recovery ("LTCRER") is a 0.144 cents/kWh credit. RI Energy proposes to adjust this by adding the LTCRER Reconciliation Factor of 0.230 cents/kWh,[1] bringing the net LTCRER to 0.086 cents/kWh starting April 1, 2023 through June 30, 2023. The LTCRER Reconciliation Factor is used to collect (or refund) any under- (or over-) recovery of Long-Term Contracting expenses. For 2022, RI Energy reports an under-recovery of approximately $16.7 million (with interest).[2] The under-recovery amount is net of REC proceeds from RECs purchased through long-term contracts for renewable energy. To estimate the REC proceeds, RI Energy must calculate a transfer price. RI Energy provided the transfer price in its workpapers, and it appears to be reasonable. Note, this factor will terminate on June 30, 2023 and a new factor will take its place for contracts July 1, 2023 to December 31, 2023. The under-recovery balance reflects an adjustment of $384,552 shown in April 2022.[3] This adjustment represents an over-recovered balance of the over-recovery incurred during 2021 and credited to customers during the period ending March 31, 2023. RI Energy'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-17, p. 1.
[2] Schedule NECO-17, p. 1.
[3] Schedule NECO-17, p. 1.