DAYMARK ENERGY ADVISORS

To: RHODE ISLAND PUBLIC UTILITIES COMMISSION

From: Richard Hahn, Matthew Loiacono, and Carlo Bencomo-Jasso, DAYMARK ENERGY ADVISORS

Date: March 19, 2018

Subject: 2018 Retail Rates Filing – Docket No. 4805, and 2018 Renewable Energy Standard (RES) Charge and Reconciliation Filing – Docket No. 4692

INTRODUCTION

On February 15, 2018, National Grid (NGrid or the Company) filed its 2018 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 2017 through December 2017. The proposed rate adjustments are effective for usage on and after April 1, 2018. 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 2018 Annual Retail Rates Filing. This filing was designated as Docket No. 4805.

On February 27, 2018, the Company filed its proposed 2018 RES Charge and RES Reconciliation. This filing consists of three attachments, which provide the calculation of the proposed RES Charge for 2018, the RES reconciliation for the period January 1, 2017 through December 31, 2017, and an analysis of the typical bill impacts of the proposed RES Charge. This filing was designated as Docket No. 4692.

On March 9, 2018, the Company filed its revised 2018 Retail Rate Filing. This filing was updated to include corrections to the original 2018 Retail Rate Filing submitted February 15, 2018 that were discovered when responding to discovery from the Division.[1] NGrid's corrections to the filing were adjustments to the SOS Adjustment Factors and the SOS Administrative Cost Factors, which included

[1] Company response to Division 1-1 in Docket No. 4805.

updates to Adam S. Crary's testimony and Schedules ASC-1 through ASC-7 and ASC-19. Specifically, the Company made the following two revisions: (1) Change the calculation of the January 2018 portion of revenue associated with the December 2017 kWh deliveries billed in January 2018; and (2) Revise the SOS expenses shown in December 2017. This revision increases the base SOS revenue for the Residential, Commercial, and Industrial groups of customers by approximately $2.9 million, $1 .0 million, and $0.2 million, respectively. The second revision removes the spot market purchases related to January 2018 from the December 2017 amount. Collectively, these revisions better align revenue applicable to the reconciliation period. These corrections result in changes to the Uncollectible Expense and SOS revenues, which lead to adjustments to the SOS Adjustment Factors and the SOS Administrative Cost. The final impact of the changes results in a typical Residential SOS customer using 500 kWh per month to now experience a bill increase of $2.17 or 2.1%, which a decrease of $0.90 or 0.7% from the initial filing. These corrections are reflected in this memo, but do not change our recommendations.

The Rhode Island Division of Public Utilities and Carriers (the "Division") has retained Daymark Energy Advisors to assist in its review of these filings 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. We do however have the following recommendations:

1. NGrid should consider using a more recent set of years to develop the allocators for assigning transmission costs to each rate class, as 2008 and 2011 are outdated.
2. NGrid should file all workpapers and schedules, in Excel format, when the Company makes future RES Charge and Reconciliation filings. This will enable more efficient audit review by the Division and Commission.

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 standard offer service 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 ASC-2, p. 1, shows a net over-recovery (with interest) of approximately $2.2 million in calendar year (CY) 2017, compared to the

over-recovery (with interest) of approximately $16.2 million in CY 2016. This CY 2017 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 2018-March 2019 to calculate three different adjustment factors, one for each procurement group. The Residential group had an under-recovery (with interest) of approximately $187,167. The Commercial and Industrial groups had over-recoveries (with interest) of $392,851 and $2.2 million, respectively. These SOS ending balances were the result of revisions made to the calculation of a part of January 2018 revenue tied to kWh deliveries made in December 2017 and billed in January 2018. The Company chose to make these revisions now to better align revenue related to this reconciliation period. Additionally, SOS expenses shown in December 2017 were reduced by approximately $2.2 million, specifically the removal of spot market purchases made in January 2018, to more completely align all SOS expenses with the reconciliation period.

The SOS reconciliation adjustment for CY 2017 included the additional following adjustments: $1,175,565 reflecting the remaining balance of CY 2015 net over-recovery SOS expenses recovered from or credited to customers during April 1, 2016 through March 31, 2017; $411,791 with interest ($304,707 allocated to residential SOS customers and $107,084 allocated to commercial SOS customers) reflecting reallocation of Spot Market purchase resettlements[2], including interest, from ISO-NE prior to January 2017 that the Company incorrectly reflected in previous annual retail rate filings; and reduced the SOS reconciliation by $137,654 for unbilled SOS Billing Adjustments for CY 2017. In this filing, the Company has reflected the correct purchase amounts for Residential and Commercial SOS customers in the SOS reconciliation adjustment and has made offsetting adjustments to the LTC Recovery Factor and Net Metering reconciliations.

On a per kWh basis, the charge with the largest magnitude SOS adjustment is the 0.830 cents/kWh (credit) for the Industrial class. The SOS adjustment for the residential class is a charge of 0.007 cents/kWh, while the Commercial class is credited 0.041 cents/kWh. This refund rate is 18% less than the high refund rate the industrial class experienced in 2015 (1.014 cents/kWh), which was previously explained by NGrid witness Mr. Crary as a combination of customer migration to alternative suppliers due to the winter of 2014-2015, invoicing errors, and a decrease in forecasted deliveries based on the prior year's customer migration. When recently asked 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

[2] The Spot Market procurements were overstated in the SOS reconciliation and understated in the LTCRER Factor and Net Metering reconciliations.

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) customer are billed on a billing cycle basis while the Company is billed for SOS expenses on a calendar month basis.[3]

Although the Company has experienced lost kWh sales over the last couple of years, it is providing an industrial SOS kWh forecast for April 2018-March 2019 that is 7% higher than the forecast for April 2017-March 2018, as shown in the figure below. In discovery, the Company explained that the increase in the forecast was due to the present proportion of kWh deliveries to Industrial SOS customers increasing from 9.53% to 10.39%, which offset the decrease in the total Industrial kWh forecast.[4]

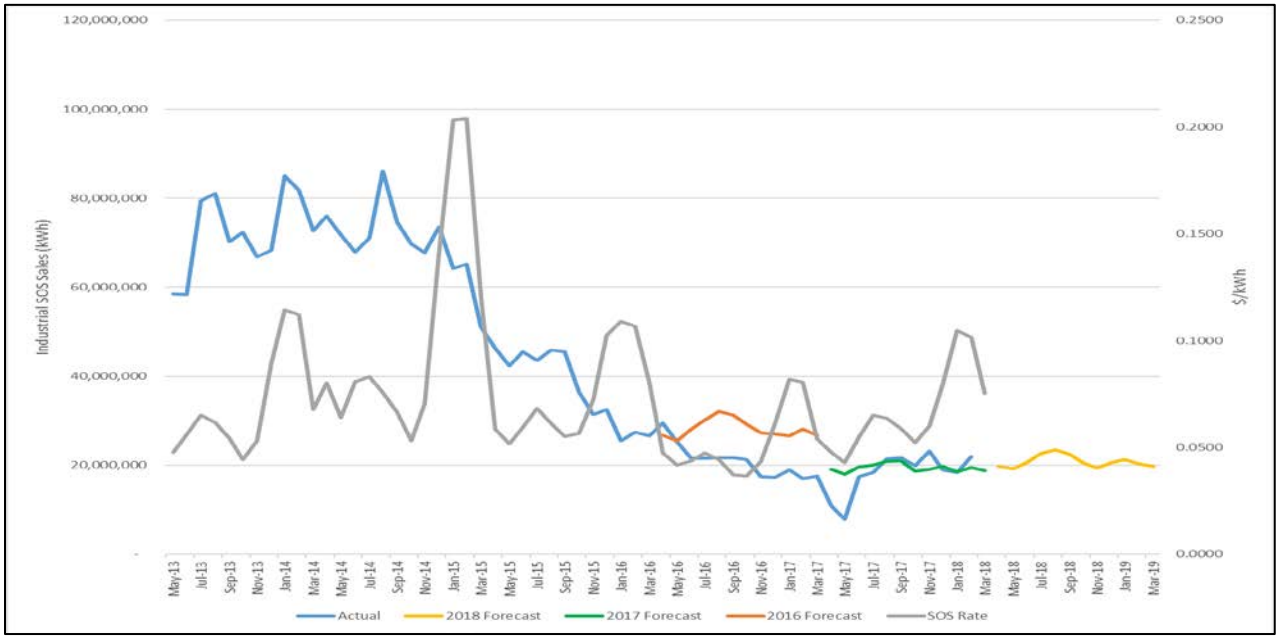

Figure 1. Actual and project SOS sales for the industrial class compared to industrial SOS rates.

Additionally, we note that the Company is proposing to charge the Residential class 0.007 cents/kWh compared to the current credit of 0.465 cents/kWh and credit the Commercial class 0.041 cents/kWh compared to the current credit of 0.304 cents/kWh. Changes in the Residential and Commercial classes' SOS adjustment factors in last year's filing, Docket 4691, were due to a transition period of the Company switching from pricing periods of January to June and July to December (2015) to periods from January to September and October to March (2016-2017). During the transition period, the first three months

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

[4] Company response to Division 1-1(c) in Docket No. 4805.

are expected to have an over-recovery due to variable rates being lower than the per kWh charge. The second three months of the transition period were expected to have higher variable rates, leading to an under-recovery. NGrid expected these to balance out during the transition period and not continue after. 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.

The administrative cost factor includes an allowance for SOS uncollectible expense and several administrative cost elements (chief of which is cash working capital). The 2018 filing shows total administrative expense of approximately $6.2 million[5] compared to approximately $5.8 million in the 2017 filing. Uncollectible expense is higher than last year due to higher projected SOS rates.[6] The cash working capital requirement is $23.4 million[7], compared to $25 million in the 2017 filing.[8]

As with the SOS adjustment factor, separate cost factors are calculated for the three customer groups. Reconciliation of these costs is added to these totals for each customer group. For the 2018 filing, the Company reports a net over-collection of 2017 administrative costs of approximately $989 (with interest).[9] While the residential and commercial customer groups showed over-collections of $97,925 and $545, respectively, the industrial customer group had an under-recovery of $97,481.[10] This net over-collection is largely due to a combination of higher revenues than expenses for both the residential and commercial customer groups.[11]

Both the estimated administrative costs and over-collection of 2018 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 2018, the adjustment charge is due to an over-collection of charges in CY 2017. The transition adjustment charge is calculated by dividing the

[5] Schedule ASC-4 Revised, p. 1.

[6] Schedule ASC-4 Revised, p.2.

[7] Schedule ASC-6 Revised, p. 1.

[8] Still substantially high because of an $80.7 million adjustment to the Customer Accounts Receivable balance in December 2014 labeled in NGrid's workpapers from Docket No. 4559 as due to reclassifying gas to electric.

[9] Schedule ASC-5 Revised, p. 1.

[10] Schedule ASC-5 Revised, pp. 2-4.

[11] Additionally, the net over-collection is still partially impacted by the December 2014 adjustment to the cash working capital requirement.

over-recovery balance from 2017 by the forecasted kWh deliveries during the recovery period, April 2018 through March 2019. This adjustment incorporates the final balance of over-recovery incurred in CY 2015.

The transition charge itself is a function of the contract termination charges (CTC) billed to NGrid by 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 filed suit against the Department of Energy (DOE) for the 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.[12] 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[13] 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[14] 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 planned to be returned to customers in this year's CTC reconciliation. In discovery, 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.[15] The discrepancy between the 2017 and 2018 Phase III litigation proceeds for Montaup and NEP was due 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. Maine Yankee's acceptance of DOE proceeds led to a periodic review of its Financial Assurance Level. Through the review and ensuing filing, it was determined that the

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

[13] 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.

[14] 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.

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

company's Spent Fuel Trust Fund was in surplus and therefore a supplemental credit of $56.6 million of the surplus was given back to wholesale customers.

Based on the credits to customers from the Phase III litigation proceeds, the base transition charge credit factor for the upcoming year is 0.083 cents/kWh. When combined with the transition charge adjustment factor credit of $0.0004 cents/kWh, the proposed total transition charge credit factor is 0.087 cents/kWh.[16] The change in the transition charge compared to last year's filing is primarily due to the changes in credits being returned to customers during CY 2017.

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 2018 costs for transmission service to be $208.1 million, as described by the testimony of Polina V. Demers. 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 2016 to 2017 increased by $34.6 million (19%), while the 2018 projected value decreases the transmission costs by $4.6 million (2%) relative to the 2017 transmission costs.

[16] Schedule ASC-9, p. 1.

NARRAGANSETT ELECTRIC COMPANY
SUMMARY OF TRANSMISSION COSTS

Ln #	Item	Feb-16	Feb-17	Incr/(Decr)	Feb-18	Incr/(Decr)	% Change
	NEP Charges						
1	Non-PTF	$ 34,823,146	$ 31,259,601	$ (3,563,545)	$ 32,871,310	$ 1,611,709	5%
2	Other NEP Charges	$ 451,891	$ 496,093	$ 44,202	$ 273,453	$ (222,640)	-45%
3	Refund Charges	$ -	$ -	$ -	$ -	$ -	
4	BITS Surcharge	$ -	$ 32,680,356	$ 32,680,356	$ 21,925,423	$ (10,754,933)	-33%
5	Subtotal	$ 35,275,038	$ 64,436,050	$ 29,161,012	$ 55,070,186	$ (9,365,864)	-15%
	ISO Charges						
6	PTF	$ 135,274,142	$ 140,564,339	$ 5,290,197	$ 145,847,743	$ 5,283,404	4%
7	Scheduling & Dispatch	$ 2,091,045	$ 2,308,148	$ 217,103	$ 2,225,931	$ (82,217)	-4%
8	Black Start	$ 923,415	$ 969,522	$ 46,107	$ 776,594	$ (192,928)	-20%
9	Reactive Power	$ 1,457,844	$ 1,371,053	$ (86,791)	$ 1,249,058	$ (121,995)	-9%
10	Resettlement Charges	$ -	$ -	$ -	$ -	$ -	
11	Subtotal	$ 139,746,446	$ 145,213,062	$ 5,466,616	$ 150,099,326	$ 4,886,264	3%
	ISO Administrative						
12	Sched 1 Schedul/Disp	$ 2,895,142	$ 2,778,212	$ (116,930)	$ 2,625,632	$ (152,580)	-5%
	Sched 3 Rel Admin Ser	$ 188,658	$ 190,145	$ 1,487	$ 192,185	$ 2,040	1%
13	Sched 5 NESCOE	$ 46,152	$ 104,564	$ 58,412	$ 95,784	$ (8,780)	-8%
14	Subtotal	$ 3,129,952	$ 3,072,921	$ (57,031)	$ 2,913,601	$ (159,320)	-5%
15	Total Expenses	$ 178,151,436	$ 212,722,033	$ 34,570,597	$ 208,083,113	$ (4,638,920)	-2%

Table 1. Summary of 2018 Transmission Costs

Table 2 below provides a recapitulation of the proposed decrease by major cost drivers. Of the $4.6 million decrease, a decrease of $10.8 million in the BITS Surcharge (described below) is the primary cost driver. NGrid explained that the decrease in the forecasted BITS Surcharge is due to the April 2017 BITS Surcharge including November 2016 through March 2017 surcharges.[17] The remaining balance, which is mainly composed of an increased cost for the use of the PTF transmission system ($5.3 million) and an increase in Non-PTF transmission system usage charges ($1.6 million), significantly offsets the decrease in the BITS Surcharge. The PTF Demand charges increased due to a RNS Schedule 9 rate increase related to higher transmission revenue requirements of ISO-NE transmission owners, based on estimated plant investments expected to be in-service in 2018. The increase in Non-PTF Demand charges is due to a higher estimated revenue requirement because the Company had collected lower revenues from the regional rates.

[17] Testimony of Polina V. Demers, p. 21. Company response to Division 1-3 in Docket No. 4805.

RECAP OF DIFFERENCES		
Item		**Incr/(Decr)**
PTF	$	5,283,404
Non-PTF	$	1,611,709
Other NEP Charges	$	(222,640)
BITS Surcharge	$	(10,754,933)
ISO Charges	$	(556,460)
	$	(4,638,920)
Resettlement Charges	$	-
Refund Charges	$	-
	$	-
	$	(4,638,920)

Table 2. Reasons for the 2018 Decrease in Transmission Costs

As shown in the table 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. Completion of the BITS project is slated for the end of 2018. 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).

Schedule PVD-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 19.43%, which is updated each year and was calculated using NGrid's CY 2016 FERC Form 1 data per the provisions of NEP's Electric Tariff No.1 (Line 14 note in Schedule PVD-7).

The Company developed its projection of PTF costs from a presentation by the Pool Transmission Owners Administrative Committee (PTO AC) Rates Working Group's presentation to the NEPOOL Reliability Committee/Transmission Committee at the summer meeting on July 18-19, 2017. We have reviewed this presentation and find it to be a reasonable source for a 2018 rate for Regional Network (RNS).

Regarding the calculation of the estimated 2018-2019 PTF rate made in this filing, the rate now includes an adjustment tied to the change in the federal corporate tax rate, which went into effect on January 1, 2018, reducing it from 35% to 21%. NGrid expects the change in the tax rate to cause an approximately 1.47% downward adjustment[18] to the estimated carrying charge.

The estimate of Non-PTF costs incorporates NGrid's estimates of Non-PTF plant additions.[19] These costs are estimated on a project-by-project basis. We have reviewed these estimates and find them to be reasonable.

The Company proposes to recover the estimated 2018 costs via demand and energy charges, as appropriate for each rate class. Schedule ASC-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 and 12 months ending 11/30/2011, as these are years with relatively normal weather. Using a representative sample analysis, we find the calculations in Schedule ASC-11 to be accurate. However, we recommend that in the future the Company 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 2018 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 2017 actual transmission service revenues and expenses. Schedules ASC-12 and ASC-13 provide the basis for this reconciliation. As of the beginning of 2017, the cumulative variance between revenues and expenses, not including interest, is an over-collection of $3,843,013, as calculated in ASC-12. The Company will refund this over-collection over the period of April 1, 2018 through March 31, 2019. Additional interest

[18] This adjustment was developed using NEP's forecasted transmission revenue requirement from the current Participating Transmission Owner Informational Filing in docket #RTO4-2-000. Testimony of Polina V. Demers, p. 17.

[19] Company provided a list of these additions to the Division through its response to Division 1-2 in Docket No. 4805.

during this period is estimated by the Company to be $9,189, which brings the total to be refunded to $3,852,203. It should be noted that the beginning balance at January 2017 included an amount of $1,279,794, which represents a FERC-ordered disgorgement payment the Company received and now needs to recover from customers. NGrid explains that it inadvertently included the disgorgement credit in the annual true-up of actual 2013 transmission expenses, which effectively led to the Company retuning the disgorgement refunds to customers again.[20] Schedule ASC-13 determines the cents/kWh rate for each customer class that will be refunded to each class' share of the over-collection. Using a representative sample analysis, we find the calculations in Schedule ASC-11 to be accurate.

We find the Company's 2018 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 1.25% of the estimated amount of transmission costs to be incurred during 2018. Schedule ASC-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 2017. This reconciliation occurs only for actual 2017 revenue. Schedule ASC-15 provides these reconciliations calculations. Using a representative sample analysis, we find the calculations in Schedule ASC-14 and ASC-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 0.043 cents/kWh[21] from 0.023 cents/kWh. In calculating the Net Metering reconciliation, the Company included an adjustment in January 2017 of $97,614, which represents additional energy sales for Net Metering and Qualifying Facilities that were resettled before January 2017 through the ISO-NE and not previously expressed in the annual retail rate filings of the Company. This adjustment offsets understated total Energy Sales to the ISO-NE from the Company for Net-Metered Customers or overstated Qualifying Facilities Power

[20] Testimony of Adam S. Crary, p. 25.

[21] Schedule ASC-16, p. 1.

Purchase Recoverable Costs in reconciliations from previous years.[22] 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 0.519 cent/kWh charge. NGrid proposes to add to this a LTC Recovery Reconciliation Factor of 0.068 cent/kWh[23], in accordance with tariff R.I.P.U.C. No. 4673. The LTC Recovery Reconciliation Factor is used to collect (or refund) any under- (or over-) recovery of LTC expenses. For 2017, NGrid reports an under-recovery of approximately $4.96 million (with interest) compared to $7.6 million (with interest) in 2016. The under-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. The under-recovery balance reflects an adjustment of $510,905 shown in January 2017.[24] This adjustment represents additional energy sales tied to LTC facilities resettled before January 2017 through ISO-NE and were not previously included in the annual retail rate filings of the Company. This adjustment is to reflect the correct net proceeds to all customers billed the LTC Recovery Factor. 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.

ADDITIONAL ADJUSTMENTS IN THE 2018 FILING

The Company explained that it adjusted revenue in January 2017 in reconciliations for transmission, SOS, transition, and LTC. These adjustments represented supplementary revenue that was unintentionally not billed to a single large customer because of an incorrectly programmed meter at the service location of the customer. The meter was correctly reprogrammed in September 2016, but until then it understated usage leading to the Company under-billing the customer. The customer was not rebilled by the Company since the issue was not caused by the customer's actions. NGrid decided to include additional revenue and interest, where applicable, in the reconciliations and plans to make similar adjustments in future reconciliation filings. We have reviewed the Company's additions of revenue and interest throughout the schedules and find them reasonable.

[22] Testimony of Adam S. Crary, p. 35.

[23] Schedule ASC-18, p. 1.

[24] Testimony of Adam S. Crary, p. 39.

RENEWABLE ENERGY STANDARD CHARGE AND RECONCILIATION

In its February 27, 2018 filing in Docket 4692, the Company seeks approval for a proposed 2018 Renewable Energy Standard (RES) Charge of $0.00004 per kWh. The charge consists of two components. The first component is the estimated cost of complying with the RES for 2018, estimated by NGrid to be $0.00190 per kWh. The second component is the adjustment charge to reconcile previous estimates of the cost of complying with prior years' RES with actual costs, ($0.00186) per kWh.[25]

The first component - $0.00190 per kWh – is based upon estimated REC prices of $15.83 for new RECs and $1.59 for existing RECs.[26] These prices are consistent with recent actual purchases made by the Company and our outlook of the current REC market, and we find them to be reasonable. The proposed charge is based upon the 2018 RES values that require new RECs to be 11% of supply obligation and existing RECs to be 2.0%. Using the above assumptions, we concur with the Company's calculation of the $0.00190 per kWh figure.

The proposed adjustment charge is ($0.00186) per kWh, which means that the adjustment charge is a credit. The cumulative over-collection as of December 31, 2017 is $9,155,165.[27] The Company estimates that it will spend an additional amount of $2,028,060 in the first half of 2018 to complete the acquisition of the remaining RECs needed for the 2017 RES obligation.[28] We examined in detail the calculation of the cumulative over-collection and the estimate of the remaining 2018 costs for 2017 compliance. We found that the amount of over-recovery carried over from 2016 to 2017 was about $2.5 million more than the amount of over-recovery carried over from 2017 to 2018. NGrid previously explained in response to discovery in its 2017 RES Reconciliation Filing that due to REC market prices significantly dropping compared to the Company's estimation of REC prices the Company was experiencing a similar over-recovery of about $11.6 million during 2015 to 2016 and 2016 to 2017. Additionally, NGrid explained that this trend has continued over the last couple years.[29] The Company provided confidential data on its REC revenue and purchases. Due to the confidentiality of this data, we will not summarize it here. We have performed a sufficiently robust investigation to verify the reasonableness of this information.

Based upon the above discussion, we find the proposed 2018 Renewable Energy Standard (RES) Charge of $0.00004 per kWh to be reasonable and recommend that it be approved. However, we recommend

[25] Docket No. 4692, Attachment 1, p. 1.
[26] Id.
[27] Id., p. 2.
[28] Id., p. 2.
[29] Company response to Division 1-5 in Docket No. 4692.

the Company to file all workpapers and schedules, in Excel format, when the Company makes future RES Charge and Reconciliation filings. This will enable more efficient audit review by the Division and Commission.

Matthew C. Loiacono

Consultant

SUMMARY

Matthew C. Loiacono works with electricity and gas clients on matters including rates, grid modernization, capital expenditures, and net energy metering. He has analyzed approaches to renewable resource integration and the benefit-cost of various modes of participation on wholesale energy market performance. He advises clients on energy procurement strategy and administers procurement auctions on their behalf. Mr. Loiacono is proficient in GIS software, SAS, and Minitab, and is an advanced user of IMPLAN.

TESTIMONY EXPERIENCE

- **Rhode Island Division of Public Utilities and Carriers.** Testified on National Grid's 2017 Retail Rates Filing (Docket No. 4691) and 2017 Renewable Energy Standard Charge and Reconciliation Filing (Docket No. 4605).
- **Blackstone Gas Company.** Conducted load forecast and assisted in drafting the 2013 and 2015 Long Range Supply (or Integrated Resource) Plans for Blackstone Gas Company (DPU 14-138 and DPU 16-185 – case pending). (2014 – present)
- **Texas Coast Utilities Coalition.** Assisted in drafting testimony on the CenterPoint Energy Resources Corporation 2016 Purchase Gas Adjustment filing (GUD No. 10567). (2017)
- **Illinois Attorney General.** Reviewed, analyzed, and assisted in filing testimony on natural gas utility accelerated infrastructure replacement programs and supporting long-term capital plans, leak rates, risk ranking systems, and rate recovery mechanisms filed by Peoples Gas (ICC Docket No. 16-0376). (2016 – present)
- **Utah Public Service Commission.** Assisted in drafting testimony regarding a proposed merger between Questar and Dominion (Docket No. 16-057-01). (2016)
- **New Hampshire Public Utilities Commission.** Assisted in drafting testimony regarding the Liberty Tennessee Gas Pipeline Precedent Agreement (DG 14-380). (2015)
- **Massachusetts Attorney General.** Reviewed, analyzed, and assisted in filing testimony on natural gas utility accelerated infrastructure replacement programs and supporting long-term capital plans, leak rates, risk ranking systems, and rate recovery mechanisms filed by gas utilities (DPU 14-130, DPU 14-131, DPU 14-132, DPU 14-133, DPU 14-134, and DPU 14-135). (2014-2015)
- **Maryland Office of People's Counsel.** Reviewed, analyzed, and assisted in filing testimony on natural gas utility accelerated infrastructure replacement programs and supporting long-term capital plans, leak rates, risk ranking systems, and rate recovery mechanisms filed by gas utilities (Case Nos. 9331, 9332, and 9335). (2014 - present)

PROFESSIONAL EXPERIENCE

Cost Allocation, Rate Design & Rates

- **Pennsylvania Office of Consumer Advocate and Maryland Office of People's Counsel.** Audited Purchase Gas Cost filings for various utilities. Presented findings and provided hearing preparation support for clients. (2015 – present)
- **Massachusetts Department of Energy Resources and Maryland Office of People's Counsel.** Audited and evaluated natural gas and electric utility rate case filings requesting an increase in base rates for various utilities. Presented findings and provided hearing preparation and briefing support for clients. (2016 – present)
- **Pennsylvania Office of Consumer Advocate.** Evaluated Default Service Programs proposed by various utilities in regards to supply mix, procurement lengths, load shapes, and rate classes. Prepared direct testimony on behalf of witnesses. (2015 – present)
- **Massachusetts Attorney General, Maryland Office of People's Counsel and Illinois Attorney General.** Investigated natural gas utility accelerated infrastructure replacement programs and supporting long-term capital plans, leak rates, risk ranking systems, and rate recovery mechanisms filed by gas utilities in three states. Prepared direct testimony on behalf of witnesses. (2014 – present)
- **New Hampshire Public Utility Commission.** Analyzed current net energy metering rate structures and evaluated proposed changes submitted by multiple utilities and other interveners. (2016 – 2017)
- **Kauai Island Utility Cooperative.** Analyzed current rate structures in Hawaii to support restructuring of rates to incorporate increased revenue needs and increased residential solar production. (2015 – present)
- **Blackstone Gas Company.** Conducted load forecasts under a variety of weather and design day criteria and reported the analysis on behalf of Blackstone Gas Company in support of their 2013 and 2015 Long Range Supply (or Integrated Resource) Plans. (2014 – present)
- **Massachusetts Attorney General and Massachusetts Department of Energy Resources.** Evaluated gas utility long-term forecast and supply plans in multiple jurisdictions including their plans for growth through conversions plus pipeline capacity restructuring decisions to relinquish long-haul pipeline and storage capacity in favor of direct field access and participation in downstream pipeline expansion projects to access more Marcellus gas supply. Presented findings and provided hearing preparation support for clients. (2015 – 2016)
- **Massachusetts Attorney General and New Hampshire Public Utility Commission.** Evaluated Precedent Agreements for Market and Supply Paths for multiple jurisdictions. Reported analysis of findings and provided support during hearings for clients. Prepared direct testimony on behalf of witness for New Hampshire Public Utility Commission in Docket DG 14-380. (2015 – 2016)
- **Massachusetts Department of Energy Resources.** Evaluated and compared electric utility grid modernization filings. Reported analysis of the filings to client. Assisted in the drafting of briefs. (2016 – 2017)
- **Nova Scotia Small Business Advocate.** Investigated Nova Scotia Power Inc.'s 2015 Annual Capital Expenditures Plan. Presented findings to the team. (2015 – 2016)
- **Manitoba Public Utilities Board.** Provided advisory services on matters related to the Manitoba Hydro Cost of Service Application, which included preparing presentations to the Board and a drafting sections of the final report. (2016)
- **Rhode Island Division of Public Utilities and Carriers.** Audited National Grid's 2017 Annual Retail Rate and Standard Offer Service Filing . (2017)

- **Texas Coast Utilities Coalition.** Investigated and prepared direct testimony on behalf of the witness regarding FERC litigation expenses and financial hedging costs presented by CenterPoint Energy Resources Corporation in its 2016 Purchase Gas Adjustment filing. (2017)
- **Utah Public Service Commission.** Analyzed current net energy metering rate structures and evaluated proposed changes submitted by Rocky Mountain Power and other interveners. (2017)
- **Washington Attorney General.** Investigated and prepared direct testimony on behalf of the witnesses regarding stranded costs, which were presented in separate dockets by Puget Sound Energy (Large Customer Retailing Docket UE-161123) and Pacific Power and Light Company (Docket UE-161204). (2017)

Renewables

- **Private Client.** Evaluated the potential to integrate wind and battery resources into NYISO. Researched and analyzed studies conducted and practices implemented by other North American utilities regarding the integration of renewable resources. (2015)
- **Private Client.** Evaluated merchant renewable transmission projects in New England using a capital budgeting model. (2015)
- **Private Client.** Collaborated in development of a decision framework to assess the potential value to utility ratepayers of direct investment in natural gas pipeline or transmission projects importing energy from New York or Canada under the New England Governor's Infrastructure Initiative. (2015)
- **Private Client.** Analyzed the potential value options of ISO New England, New York ISO and PJM for a company seeking to offer the output of its hydro unit into one of these regional markets. (2015)
- **Massachusetts Clean Energy Center.** Analyzed and reported on the economic impacts of growth in the energy storage technology industry over the next decade as part of an energy storage industry study. (2015 – 2016)

Regulation & Policy

- **New Brunswick Public Intervener.** Investigated and prepared direct testimony on behalf of witness regarding compliance of the non-rate terms and conditions of New Brunswick Power's proposed OATT with FERC policy and evaluated the reasonableness of the proposed ancillary services revenue requirements and rates. (2014 – 2015)
- **New Brunswick Public Intervener.** Investigated and prepared direct testimony on behalf of witness regarding Algonquin Tinker GenCo's revenue requirement: evaluation of need for requested transformer upgrade, ROE, allocation of common plant to transmission and application of FERC cost allocation principles. (2014 – 2015)
- **Private Client.** Investigated and prepared direct testimony on behalf of witness regarding the critique of proposed changes to ISO-NE Tariff provisions regarding the Dynamic Delist Bid Threshold, Static Delist Bid submission and adjustment process, and the Pivotal Supplier Test. (2015)
- **Private Client.** Evaluated the economic impacts of infrastructure buildout levels in New England. Estimated impacts of expansion of natural gas pipeline and electricity generation (renewable and non-renewable) on energy costs and regional economic indicators (employment, income, and competitiveness). Assisted in an update to the original research that involved the explanation of state and federal policy implications impacting New England since August 2015. (2015 – 2016)

- **Utah Public Service Commission.** Investigated and prepared direct testimony on behalf of witness regarding a proposed merger between Questar and Dominion. Reviewed and provided deficiencies in the proposed merger based on the potential value to consumers of Questar. (2016)
- **Private Client.** Utilized SAS to evaluate the demand curve reset model used by NYISO and gave a presentation on the findings from the analysis. (2016)

Utility Planning

- **NRG.** Investigated and prepared an alternative technology comparison, discussion of consistency with the Commonwealth's Energy and Environmental Policies, and testimony and case support regarding a Siting Board application for a new natural gas-fired unit in Massachusetts. (2015 – 2016)

Power Procurement & Load Bidding

- **National Passenger Railroad Corporation (Amtrak).** Advised client in utility interconnection issues, rates, special contracts and other rate designs, and retail purchase power procurement and power supply management for 200+ MW portfolio of traction and non-traction accounts in eight states and three northeastern U.S. control areas. (2015 – present)
- **Private Client.** Conducted weekly load bidding into ISO-NE market. Advised client on other issues, including wholesale purchase power procurement and power supply management. (2015 – present)
- **Woodsville Water & Light (NH).** Drafted budget for the next calendar year and provided monthly report that compared actual load and cost data to the budgeted data. Advised the utility on other issues, including retail purchase power procurement and power supply management. (2015 – present)
- **Narragansett Bay Commission (RI).** Advised the utility on other issues, including retail purchase power procurement and power supply management. (2016 – present)

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc. *(formerly La Capra Associates, Inc.)*	Boston, MA
Consultant	Mar. 2017 – Present
Senior Analyst	2016 – Feb. 2017
Analyst	2014 – 2016
Monitoring Analytics, LLC	Eagleville, PA
Market Analyst	2011 – 2014
UgMO Technologies, Inc.	King of Prussia, PA
Field Operations Manager-ProTurf / Agronomic Data Analyst	2009 – 2011

EDUCATION

Pennsylvania State University	University Park, PA
M.S., Agricultural, Environmental & Regional Economics	2008
University of Delaware	Newark, DE
B.S., Natural Resource Management and minor in Resource Economics	2006