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Rhode Island Energy™
a PPL company

December 22, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 22-49-EL-The Narragansett Electric Company d/b/a Rhode Island Energy Advanced Metering Functionality Business Case
Compliance Filing

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), enclosed are the following documents submitted in compliance with the Rhode Island Public Utilities Commission's (the "Commission") September 27, 2023 Open Meeting motions and votes approving with conditions the Company's Advanced Metering Functionality ("AMF") Business Case (the "Decision"):[1]

- The Narragansett Electric Company d/b/a Rhode Island Energy's Certification;
- A proposed Infrastructure, Safety, and Reliability Provision, RIPUC No. 2273, to supersede RIPUC No. 2255, redlined to show the proposed revisions to RIPUC No. 2255 to add the Addendum for AMF cost recovery;
- A revised version of the Company's response to Record Request 9 to reflect the revisions required by the Commission in the Decision; and
- A revised version of the Company's response to data request PUC 7-13 to reflect the updates required by the Decision.

The Company is in the process of completing a revised Attachment H excel spreadsheet, which also is required by the Decision. Once that is complete, the Company will file it under separate cover.

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

Thank you for your time and attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket No. 22-49-EL Service List

CERTIFICATE OF SERVICE

I certify that a copy of the within documents was forwarded by e-mail to the Service List in the above docket on the 22nd day of December, 2023.

Adam M. Ramos, Esq.

The Narragansett Electric Company d/b/a Rhode Island Energy
Docket No. 22-49-EL Advanced Meter Functionality (AMF)
Service list updated 7/24/2023

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STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

In re: The Narragansett Electric Company d/b/a Rhode Island Energy's Advanced Metering Functionality Business Case	)))))	Docket No. 22-49-EL

THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY'S CERTIFICATION

The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") respectfully submits this Certification in accordance with Paragraphs 5 and 16 of the Rhode Island Public Utilities Commission's (the "Commission") September 27, 2023 Open Meeting motions and votes ("Decision") approving with conditions the Company's Advanced Metering Functionality ("AMF") Business Case, a copy of which is attached as Exhibit 1.

The Company commits to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved Capex Cap (as that term is defined in the Decision) for those investments identified in the scope of the implementation plan as set forth in the Company's revised response to Record Request 9, which is being submitted contemporaneously with this Certification. The Company further confirms that it will move forward with implementing AMF under the terms of the Commission's authorization and subject to the conditions set forth by the Commission in the Decision.

---------- SIGNATURE PAGE FOLLOWS ----------

THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY

By its President,

Dave J. Bonenberger
The Narragansett Electric Company d/b/a
Rhode Island Energy
280 Melrose Street
Providence, RI 02907

Dated: December 22, 2023

CERTIFICATE OF SERVICE

I hereby certify that on December 22, 2023 I sent a copy of the foregoing to the service list by electronic mail.

/s/ Adam M. Ramos

EXHIBIT 1

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: RHODE ISLAND ENERGY ADVANCED	**:**	
METERING FUNCTIONALITY BUSINESS CASE	**:**	**DOCKET NO. 22-49-EL**
AND COST RECOVERY PROPOSAL	**:**	

OPEN MEETING MOTIONS AND VOTES

Finding of Need and Authorization for Deployment

(1) Move to find that there is a need for the Company to transition its electric distribution operations from the existing AMR-based metering system to a system that utilizes advanced metering functionality (AMF). RG, AA Vote 3-0

Capital Cost Recovery through the ISR

(2) Move to reject the Company's proposal for a new AMF recovery factor. RG, AA Vote 3-0

(3) Move to authorize the Company to seek recovery of its capital investments in the categories identified in Record Request 9 through the infrastructure, safety, and reliability (ISR) process as discretionary investments through the creation of a separate category with an overall multi-year CapEx cap, with the following conditions:

(a) The Company is not required to prove a need to deploy AMF for its electric distribution operations in place of the existing AMR-based metering system;

(b) The scope of the authorized deployment includes the investments and functionalities, as set forth in Figure 6.2 and Figure 6.3 but shall not include CP:Solar Marketplace, CP:Carbon Footprint Calculator, and CP: C&I and Multi-Family Portfolio View.

(c) The scope shall also include advancement of load disaggregation & Waveform Analytics and Grid Edge Computing that will be enabled by allowing customers to use Sense by connecting their home area network to the meter as discussed in RR-11 and shall not include acceleration of TVR.

(d) Capital spending within the scope of Record Request 9 (Project Implementation) that was commenced prior to the ISR Fiscal Year 2025 filing shall be eligible for ISR recovery notwithstanding the fact that the spending was not part of the pre-approved investments within the rules of a prior ISR filing;

(e) Recovery of the capital costs incurred for the authorized project implementation period shall be capped in the aggregate at a budget of $153,217,548 and the Company is directed to file a revised RR-9 and revised Attachment H excel spreadsheet to reflect $0.00 for the items removed and to show the O&M related to acceleration of Sense.

(f) Regarding the Special Sector Deferrals identified in the Amended Settlement Agreement and listed in Attachment PUC 7-13, lines 3 and 4, the ongoing annual net cumulative accrual shall only be used to offset the annual AMF revenue requirement that is eligible for ISR cost recovery each year.

RG, AA Vote 3-0

(4) Move that the Meter Data Management System (MDMS) costs shall not be eligible for rate base recovery; provided, however, 44% of the capital costs associated with the work performed by Landis+Gyr which the Company allocated to AMF shall be amortized over the depreciation period applicable to the asset type and recovered through the ISR without a return. RG, AA Vote 3-0

(5) When the Company submits its compliance filing, it needs to certify that it is committing to making the investments, achieving the functionalities identified above, and bearing the financial risk of exceeding the approved Capex Cap for those investments identified in the scope of the implementation plan as set forth in Record Request 9 minus the capex related to the three items previously removed. RG, JR Vote 3-0

(6) Move to direct the Company to file an ISR Addendum to encompass the findings herein for further review by the Commission. The addendum shall include a proposal to recover the revenue requirement associated with the eligible AMF CapEx spending to be appropriately allocated to each rate class and recovered through a fixed charge embedded in the applicable customer charge for each rate class for further review by the Commission. RG, AA Vote 3-0

Treatment of O&M Expenses Prior to Next Rate Case

(7) Move that any operation and maintenance (O&M) expenses (i) relating to the AMF project implementation period or (ii) relating to AMF "run-the-business" costs, which expenses are incurred during the period prior to new base distribution rates going into effect from the next base distribution rate case may not be deferred or recovered in any new rates. RG, AA, Vote 3-0

(8) Move that effective on the date of this decision through the effective date of the Company's next base distribution rates, the Company may net O&M expenses that relate to the AMF scope as defined above against the accumulating regulatory liability relating to certain residual revenue requirement items identified in Docket 4770 and enumerated in PUC 7-13, RR-7, and/or RR-13. To the extent that such O&M expenses during that period are less than the total accumulated regulatory liability as of the date that new base distribution rates go into effect, the regulatory liability shall remain in effect and the balance shall be applied for the benefit of ratepayers in a manner determined by the Commission. RG, JR Vote 3-0

(9) Move to direct the Company to file a schedule that updates Attachment PUC 7-13 with actuals through Rate Year Ending August 31, 2023, includes the AMF-related portion of all other grid mod costs identified on line 25, page 7 of 9, Compliance Attachment 1 in the Docket No. 4770 Compliance Filing (Amended Settlement Agreement Book 1) that was identified in SAB/BLJ-1, and provides a forecast through the anticipated effective date of the next base distribution rate case. In addition, the Company shall provide the cumulative balances as of August 31, 2023 in a separate section. RG, JR Vote 3-0

(10) Move to direct the Company to update the revised schedule that was just voted on with each annual ISR filing and reconciliation filing and also include a schedule which shows the O&M expenses that have been netted against the rate level credit balance. RG, JR Vote 3-0

Accountability Requirements

(11) Move that the effect of the CapEx cap is that the Company will be required to keep spending, even if above the cap, until it achieves the functionalities as set forth in prior motions today. AA, JR Vote 3-0

(12) Move to adopt the following requirements the Company must comply with under the authorization to advance its AMF investment plan:

<u>ADMS Integration</u>: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the meter data is integrated into the ADMS. The company should report on the number of meters installed, time to install the meters, integration with ADMS, and any outliers. Prior to commencing meter installation the company needs to provide the PUC and DPUC definitions of the geographic deployment areas.

<u>Voltage Notification</u>: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that the company has configured real time alerts for over/under voltage and is using the ADMS ping to investigate voltage issue.

<u>Outage Notification</u>: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for outage notification.

<u>Remote Connect/Disconnect</u>: Within two months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for remote connect, disconnect, service activation, and account transfers.

<u>Theft Detection</u>: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that it is relying on the meters for theft detection.

<u>Customer Portal</u>: Company will maintain a customer portal. At a minimum, there should be no discontinuity of customers' ability to access account information and pay bills online.

Load Disaggregation: Within twelve months of meter installation in each geographic deployment area, the company must provide evidence that customers are able to access disaggregated load data. Within 12 months of the conclusion of the deployment period, the company will report on customer access and utilization of disaggregated load data.
AA, JR Vote 3-0

(13) Move that within two months of the start of meter installation, the Company must file plans that address Green Button Connect, Home Area Network, and Grid Edge Computing, as described below. The company may consult with any stakeholder deemed necessary, but the plan must be filed by the company and will be reviewed by the Commission in a contested proceeding.

Green Button Connect: Within two months of the start of meter installation, the company must file a Green Button Connect plan that addresses the following:

a. For every customer specific item on the bill, whether that same information should be provided through GBC;
b. At a minimum, the company should plan to provide the same data fields and historical information as offered or planned to be offered to its customers in Pennsylvania and Kentucky.
c. For each of the items in (a), whether the underlying customer-specific data (e.g. interval meter reads, voltage) should be provided through GBC;
d. To the extent historical data is provided for (a) and (b), provide the extent of that data set. Specifically address whether it is appropriate to provide 36 months of electric consumption.
e. Whether (a), (b), and (c) should be provided for gas.
f. Whether any additional customer specific data beyond (a) and (b) should be provided through GBC (e.g. disaggregated load data).
g. Timeline for GBC certification and version of certification.

Home Area Network: Within two months of the start of meter installation, the company must file a Home Area Network plan that addresses the following:

h. Version of bring-your-own-device that will be offered to customers, and requirements, if any, on those devices;
i. Access to usage and disaggregation insights;
j. Whether any charges apply to customers or device-makers;
k. Technical standards for local devices;
l. Terms and conditions on direct upload of usage data and disaggregation insights.

Grid Edge Computing: Within two months of the start of meter installation, the company must file a Grid Edge Computing plan that presents a framework or terms and conditions for each issue identified in Mission:data Coalition's Post-Hearing Statement section 3, parts (a) through (f).
AA, JR Vote 3-0

(14) Move to direct Rhode Island Energy to engage with the DPUC to negotiate the details and implementation of the following service quality mechanisms and file an updated Service Quality Plan for Commission review and approval in Docket 3628 within 3 months. Other parties will be able to intervene in Docket 3628.

1. Meter reading & billing:
    a. Monthly percent of meters read is an existing reporting requirement in the service quality plan in Docket 3628.
    b. The company will be subject to a meter reading & billing service quality mechanism at the end of the TSA period.
    c. The service quality mechanism should establish a threshold that represents appropriate performance (e.g. the average of the past three years).
    d. The maximum penalty will be imposed for performance 2.5 standard deviations below the threshold.
    e. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum penalty was determined.
    f. The design may or may not be linear, and it may include a dead band.
    g. Following the meter installation period, the Company and Division may propose an update to this service quality mechanism in Docket 3628.
2. Faster outage notification:
    a. The company will be subject to a one-time faster outage notification service quality mechanism 12 months after full project implementation.
    b. The service quality mechanism should establish a baseline for outage notification.
    c. The maximum penalty will be imposed if evidence shows that the company is notified of outages 0 minutes faster than the baseline.
    d. No penalty will be imposed if evidence shows that the company is notified of outages 22 minutes faster than the baseline.
    e. The metric may be an annual average over all customers or explain why a different metric was chosen.
    f. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.
    g. The mechanism may or may not be linear. Intervals, bins, and dead-bands may be considered.
    h. The mechanism may (but is not required to) include a shared savings mechanism for evidence that that the company is notified of outages more than 23 minutes faster than the baseline.
3. Network speed:
    a. The company will be subject to a one-time or continuous network speed service quality mechanism 12 months after full project implementation.
    b. The service quality mechanism should establish a measurement of network speed. The measurement should capture the speed of information from the meter to the MDMS and back to the customer portal or explain why a different measurement

was chosen. The service quality mechanism should establish the time period and scope of the measurement.

c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.

d. The company and parties should propose the maximum penalty and threshold. Intervals, bins, and dead bands may be considered.

4. Trouble, Non-Outage
   a. Trouble, non-outage calls are an existing reporting requirement in the service quality plan in Docket 3628.
   b. Within twelve months after meter installation starts, the company will be subject to a service quality mechanism for trouble, non-outage calls.
   c. The service quality adjustment should impose scaled penalties for increased trouble, non-outage calls, compared to a baseline. The metric, baseline, minimum, and maximum should be defined and justified.
   d. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.
5. Customer satisfaction
   a. Customer satisfaction (customer contact survey) is an existing service quality mechanism in the service quality plan in Docket 3628.
   b. Within six months after meter installation starts, the company will be subject to an updated customer contact standard that reflects the company's expectations of higher customer satisfaction. Updates may include, but not be limited to, increasing the minimum percent satisfied threshold, increasing the value of the penalty, and narrowing the dead band.
   c. The maximum penalty should be generally consistent with existing potential penalties in Docket 3628 (i.e. between $200,000-$1,000,000), or show why a higher maximum was chosen.

AA, JR Vote 3-0

Conclusory Motions

(15) The Commission authorizes the Company to deploy an AMF-based metering system for the electric distribution business subject to the conditions already voted on. RG, AA Vote 3-0

(16) The Company is not required to commence the authorized project implementation. The decision to move forward under the terms of the Commission's authorization rests within the management discretion of the Company; provided, however, if such project implementation is commenced, the conditions set forth by the Commission in the decisions today shall apply. RG, AA Vote 3-0.

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

In accordance with the provisions of *An Act Relating to Public Utilities and Carriers – Revenue Decoupling*, the prices for electric distribution service contained in all of the Company's tariffs are subject to adjustment to reflect the operation of its Electric Infrastructure, Safety, and Reliability ("ISR") Provision.

I. Infrastructure Investment Mechanism

A. Definitions

"Actual Capital Investment" shall mean the sum of i) "Discretionary Capital Investment" and ii) "Non-Discretionary Capital Investment", as defined below, plus cost of removal.

"CapEx Factor" shall mean the per-kWh factor for non-demand rate classes designed to recover the Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, based on Forecasted kWh for the Current Year for each non-demand rate class. For demand-based rate classes Rate G-02, and Rates G-32/B-32, the CapEx Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for each demand-based rate class.

"CapEx Reconciling Factor" shall mean the per-kWh factor designed to recover or refund the over or under billing of the actual Cumulative Revenue Requirement, as allocated by the Rate Base Allocator, for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

"Cumulative CapEx" shall mean the cumulative Actual Capital Investment for years prior to the Current Year plus Forecasted Capital Investment for the Current Year, recorded since the end of the Company's rate year in its most recent general rate case and reflecting any difference between Actual Capital Investment and Forecasted Capital Investment for any period during which Forecasted Capital Investment has not been reconciled to Actual Capital Investment, including through the end of the Company's rate year in its most recent general rate case.

"Cumulative Revenue Requirement" shall mean the return and taxes on year-end cumulative Incremental Rate Base, at a rate equal to the pre-tax weighted average cost of capital as approved by the Commission in the most recent proceeding before the Commission, plus the annual depreciation on Cumulative CapEx as defined above, plus the annual municipal property taxes on Cumulative CapEx, as calculated in the illustration below.

"Current Year" shall mean the fiscal year beginning April 1 of the current year and running through March 31 of the subsequent year during which the proposed CapEx Factor and O&M Factor will be in effect.

"Discretionary Capital Investment" shall mean capital investment, other than 'Non-Discretionary' Capital Investment defined below, approved by the Commission as part of the

Company's annual electric ISR Plan and shall be defined as the lesser of a) actual 'discretionary' electric plant in service or b) approved 'discretionary' capital spending for Discretionary Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Forecasted Capital Investment" shall mean the estimated capital investment and cost of removal anticipated to be incurred/recorded by the Company for a given fiscal year associated with electric distribution infrastructure consistent with its capital forecast.

"Forecasted kWh" shall mean the forecasted amount of electricity, as measured in kWh, to be distributed to the Company's distribution customers for the twelve month period during which the proposed factors, as defined in this ISR Provision, will be in effect.

"Incremental Rate Base" shall mean the Cumulative CapEx adjusted for accumulated depreciation and calculated accumulated deferred taxes on Cumulative CapEx since the end of the Company's rate year in its most recent general rate case, and reflecting any difference between Actual Capital Investment and Forecasted Capital Investment , including through the end of the Company's rate year in its most recent general rate case.

"Non-Discretionary Capital Investment" shall mean capital investment related to the Company's commitment to meet statutory and/or regulatory obligations which amount shall be approved by the Commission as part of the Company's annual electric ISR Plan and shall be defined as the lesser of a) 'non-discretionary' electric plant in service or b) actual 'non-discretionary' capital spending for 'Non-Discretionary' Capital Investment plus related cost of removal recorded by the Company for a given fiscal year associated with electric distribution infrastructure.

"Rate Base Allocator" shall mean the percentage of total rate base allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

B. Recovery Mechanism

The CapEx Factors shall recover the Cumulative Revenue Requirement on Cumulative CapEx as approved by the Commission in the Company's annual Electric ISR Filings. The CapEx Factors shall be applicable for the twelve-month period commencing April 1.

The Company's electric ISR mechanism shall include an annual CapEx Factor reconciliation which will reconcile actual Cumulative Revenue Requirement to actual billed revenue generated from the CapEx Factors for the applicable Current Year. The recovery or refund of the reconciliation amounts (either positive or negative) shall be reflected in CapEx Reconciling Factors. The Company shall submit a filing by August 1 of each year ("Reconciliation Filing"), in which the Company shall propose the CapEx Reconciling Factors to become effective for the twelve months beginning October 1. The amount approved for recovery or refund through the CapEx Reconciling Factors shall be subject to reconciliation with amounts billed through the CapEx Reconciling Factors and any difference reflected in future CapEx Reconciling Factors.

II. Operation and Maintenance Mechanism

A. Definitions

"Actual I&M Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with its I&M Program.

"Actual VM Expense" shall mean the O&M expense recorded by the Company for a given fiscal year associated with vegetation management.

"Forecasted I&M Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with its I&M Program.

"Forecasted VM Expense" shall mean the O&M expense budgeted by the Company for a given fiscal year associated with vegetation management.

"I&M Program" shall mean the Company's Inspection and Maintenance Program and related inspection and maintenance activities.

"O&M" shall mean expenses of the Company recorded in FERC regulatory accounts 580 through 598 pursuant to FERC's Code of Federal Regulations.

"O&M Allocator" shall mean the percentage of total O&M allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

"O&M Factor" shall mean the per-kWh factor for all rate classes, except for Rate B-32, designed to recover the Forecasted I&M Expense and Forecasted VM Expense for the Current Year, as allocated by the O&M Allocator, based on Forecasted kWh for the Current Year for each rate class. For Rate B-32, the O&M Factor shall mean the per-kW factor based on Forecasted kWh for the Current Year and historic load factors for the rate class

"O&M Reconciling Factor" shall mean the uniform per-kWh factor designed to recover or refund the under or over billing of Actual I&M Expense and Actual VM Expense for the prior fiscal year, based on Forecasted kWh for the recovery/refund period beginning October 1.

B. Recovery Mechanism

The O&M Factor shall recover the sum of the annual Forecasted I&M Expense and Forecasted VM Expense as approved by the Commission in the Company's annual Electric ISR Filings. The O&M Factor shall be applicable for the twelve-month period commencing April 1.

The Company's Electric ISR mechanism shall include an annual O&M Factor reconciliation which will reconcile Actual I&M Expense and Actual VM Expense to actual billed revenue from the O&M Factor for the Current Year. The recovery or refund of the reconciliation amount (either positive or negative) shall be reflected in the O&M Reconciling Factor. In its Reconciliation Filing, the Company shall propose the O&M Reconciling Factor to become effective for the twelve months beginning October 1. The amount approved for recovery or refund through the O&M Reconciling Factor shall be subject to reconciliation with amounts billed through the O&M Reconciling Factor and any difference reflected in a future O&M Reconciling Factor.

III. Annual Electric Infrastructure, Safety, and Maintenance Plan

By January 1 of each year, the Company shall submit to the Commission for review and approval its proposed Electric Infrastructure, Safety, and Reliability Plan ("Electric ISR Plan") for the upcoming Current Year. The Electric ISR Plan shall consist of Forecasted Capital Investment, Forecasted I&M Expense, Forecasted VM Expense, and, if mutually agreed upon by the Division and the Company, the revenue requirement, whether the result of capital investment or O&M expenditures, of any other cost relating to maintaining safe and reliable electric service.

IV. Annual Report on Electric ISR Plan Activities

The Company's August 1 Reconciliation Filing shall include an annual report on the prior fiscal year's activities. In implementing its Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original plans approved by the Commission. In such cases, in the annual report, the Company would include an explanation of any deviations in excess of ten (10) percent above Forecasted Capital Investment, Forecasted I&M Expense, and Forecasted VM Expense. For cost recovery purposes, the Company has the burden to show that any such deviations were due to circumstances out of its reasonable control or, if within its control, were reasonable and prudent.

V. Adjustments to Rates

Modifications to the factors contained in this Electric ISR Provision shall be in accordance with a notice filed with the Commission setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

The Narragansett Electric Company

Illustrative ISR Property Tax Recovery Calculation

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	**RY End**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of Yr 1**
1	Plant In Service	$13,584,700	$55,000	$2,000	$57,000		($9,400)		$13,632,300
2									
3	Accumulated Depr	$611,570				$45,039	($9,400)	($7,200)	$640,009
4									
5	Net Plant	$12,973,130							$12,992,291
6									
7	Property Tax Expense	$29,743							$31,274
8									
9	Effective Prop tax Rate	0.23%							0.24%
10									
11									
12		**Yr 2 Beg**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of Yr 2**
13									
14	Plant In Service	$13,632,300	$60,000	$2,200	$62,200		($9,500)		$13,685,000
15									
16	Accumulated Depr	$640,009				$45,039	($9,500)	($7,400)	$668,148
17									
18	Net Plant	$12,992,291							$13,016,852
19									
20	Property Tax Expense	$31,274							$32,897
21									
22	Effective Prop tax Rate	0.24%							0.25%
23									
24									
25		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
26	**Property Tax Recovery Calculation**								
27			**ISR YR 1**				**ISR YR 2**		
28									
29	ISR Additions		$55,000				$60,000		
30	Rate Year Book Depr		($45,039)				($45,039)		
31	COR - ISR YR		$7,200				$7,400		
32									
33	Net Plant Additions		$17,161				$22,361		
34									
35	RY Effective Tax Rate		0.23%				0.23%		
36	Year 1 ISR Property Tax Recovery			$39				$51	
37	Year 2 ISR Property Tax Recovery							$35	
38									
39	ISR Year Effective Tax Rate	0.24%				0.25%			
40	RY Effective Tax Rate	0.23%	0.01%			0.23%	0.02%		
41									
42	RY Net Plant	$12,973,130				$12,973,130			
43	ISR Yr 1 Net Adds	$17,161				$15,291			
44	ISR Yr 2 Net Adds		$12,990,291			$22,361	$13,010,782		
45				$1,487				$3,052	
46									
47	Total ISR Property Tax Recovery			$1,526				$3,139	
48									
49	Incremental ISR Property Tax Recovery			$1,526				$1,612	

Line Notes

1 Col (a) per Rate Year cost of service, Col (b), (cc), (d) and (f) per Actual ISR filing Col (e) equals Base Rate depreciation expense allowance
3 Col (a) per Rate Year cost of service, (e) equals Base Rate depreciation expense allowanceCol (h) Col (b), (cc), (d) and (f) per Actual ISR filing
7 Col (a) Base Rate property tax expense allowance
36 Line 33 times Line 35
37 Col (g) equals Line 43, Col (e) Times Rate Year effective Property Tax Rate Line 9 Col (a) - (15,291 X 3.97%)
43 Col (e) equals Line 33, Col (b) less ISR Yr 1 additions, Line 29, Col (b) times composite book depreciation rate of 3.4% - (17,161 - 55,000 X 3.4%)
45 Line 40 times Line 44

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

ADDENDUM

Advanced Metering Functionality (“AMF”)

In accordance with the Commission’s decision in Docket No. 22-49-EL, the Company is authorized to seek recovery of AMF Capital Investments through the ISR process under a separate category. The Company is not required to prove a need to deploy AMF for its electric distribution operations in place of the existing automated meter reading metering system as part of the ISR process.

A. Definitions

“AMF Actual Capital Investment” shall mean the sum of the AMF Capital Investments that were placed in service during a given fiscal year.

“AMF CapEx Factor” shall mean the per-customer fixed charge, embedded in the applicable customer charge, for each rate class to recover the forecasted AMF Cumulative Revenue Requirement, net of the Special Sector Deferrals, as allocated by the Rate Base Allocator, based on Forecasted Customer Count for the AMF Current Year for each rate class.

“AMF CapEx Reconciling Factor” shall mean the per-customer fixed charge, embedded in the applicable customer charge, for each rate class designed to recover or refund the under or over billing of the actual AMF Cumulative Revenue Requirement through the AMF CapEx Factor for the prior ISR recovery period, based on Forecasted Customer Count for the recovery or refund period.

“AMF Capital Investments” shall mean capital investments associated with AMF Project Implementation, including but not limited to 1) AMF meters; 2) AMF-related network capital costs; 3) AMF-related software capital costs; and 4) the respective share of capital project management costs associated with the capital investments.

“AMF Cumulative CapEx” shall mean the cumulative AMF Actual Capital Investment placed in service for years prior to the AMF Current Year plus AMF Forecasted Capital Investment for the AMF Current Year, recorded since the beginning of AMF Project Implementation.

“AMF Cumulative Revenue Requirement” shall mean the return and taxes on year-end cumulative AMF Incremental Rate Base, at a rate equal to the pre-tax weighted average cost of capital as approved by the Commission in the most recent base distribution rate case proceeding plus the annual depreciation on AMF Cumulative CapEx plus the annual municipal property taxes on AMF Cumulative CapEx. In addition, the amortization of MDMS Capital Costs will be included in the total AMF Cumulative Revenue Requirement to be recovered through the AMF CapEx Factor and AMF CapEx Reconciling Factor.

THE NARRAGANSETT ELECTRIC COMPANY
INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

“AMF Current Year” shall mean the twelve-month period during which the proposed AMF CapEx Factor will be in effect that aligns with the start date of the ISR Plan recovery.

“AMF Forecasted Capital Investment” shall mean the estimated AMF Capital Investments anticipated to be incurred and/or recorded by the Company for a given fiscal year.

“AMF Incremental Rate Base” shall mean the AMF Cumulative CapEx adjusted for accumulated depreciation and calculated accumulated deferred taxes on AMF Cumulative CapEx.

“AMF Project Implementation” is the period of time in which the Company makes the investments and performs the work necessary to begin operation of the AMF meters with all the approved and required functionalities, as outlined in the Commission’s September 27, 2023, Open Meeting motions and votes approving with conditions the Company’s AMF Business Case.

“Forecasted Customer Count” shall mean the forecasted number of the Company’s electric distribution customers by rate class for the period during which the proposed factors, as defined in this ISR Provision Addendum, will be in effect.

“MDMS Capital Costs” shall mean the costs to install the Meter Data Management System (“MDMS”) components allocated to AMF, which are equal to forty-four percent (44%) of the capital costs associated with the work to install the MDMS and are separate from, and not included in, AMF Actual Capital Investment or AMF Forecasted Capital Investment.

“Special Sector Deferrals” shall mean the on-going net cumulative deferral balances related to the Special Sector Programs identified in Article II.C.20 of the Amended Settlement Agreement approved by the Commission in Docket No. 4770 (Report and Order No. 23823, issued on May 5, 2020) consisting of 1) the Energy Storage Demonstration program and 2) the Electric Transportation program.

B. Recovery Mechanism

The AMF CapEx Factor shall recover the AMF Cumulative Revenue Requirement, net of the Special Sector Deferrals, on AMF Cumulative CapEx as approved by the Commission in the annual proceeding for approval of the Company’s proposed electric ISR plan for the applicable fiscal year. The AMF CapEx Factor shall be applicable for the twelve-month period commencing at the start date of the CapEx Factor for the ISR Plan Filing. AMF Capital Investments that were commenced prior to the Company’s ISR plan filing for the twelve-month period ending March 31, 2025, shall be eligible for recovery

through this ISR Provision Addendum notwithstanding the fact that the spending was not part of the pre-approved investments within a prior ISR filing.

Recovery of costs incurred for AMF Capital Investments shall be capped in the aggregate at a budget of $153,217,548.

The MDMS Capital Costs shall not be eligible for rate base recovery by inclusion in AMF Incremental Rate Base. The MDMS Capital Costs shall be amortized over the depreciation period applicable to the asset type and recovered through the AMF Cumulative Revenue Requirement in the ISR process without a return on those costs.

The electric ISR process shall include an annual AMF CapEx Factor reconciliation, which will reconcile actual AMF Cumulative Revenue Requirement to actual billed revenue generated from the AMF CapEx Factor for the applicable AMF Current Year. The recovery or refund of the reconciliation amounts (either positive or negative) shall be reflected in the AMF CapEx Reconciling Factor. The Company shall include the AMF CapEx Factor reconciliation as part of its annual Reconciliation Filing, to become effective for a twelve-month period. The amount approved for recovery or refund through the AMF CapEx Reconciling Factor shall be subject to reconciliation with amounts billed through the AMF CapEx Reconciling Factor and any difference reflected in future AMF CapEx Reconciling Factors.

PUC 7-13 (Revised)

Data Requests Regarding Supplemental Testimony

Revenue Requirement and Recovery

Request:

Please identify **all** annual deferrals of revenue recovered in base distribution rates which arose out of rate allowances in the Multi-Year Rate Plan in Docket No. 4770 and are being held or will be held for crediting to customers. For example, there is a deferral which was identified in response to PUC 1-27 in this docket relating to preparation of the AMF business case and there were deferrals that arise out of underspending of Power Sector Transformation programs, some of which were identified in Docket No. 4770A (filed on November 3, 2021). There also are credits referenced in Schedule SAB/BLJ-1 in Book 3 of the original AMF filing in this docket Please show the annual amounts by rate year and projections of future annual amounts through the Company's forecasted date when new base distribution rates would take effect from the Company's next base distribution rate case and include the expected cumulative amounts for each deferral.

Original Response:

Please see Attachment PUC 7-13 for the forecasted deferral balances of all annual deferrals of revenue recovered in base distribution rates that arose out of rate allowances in Docket No. 4770 and that are currently in a liability position, or the Company forecasts will be in a liability position at the time of the next distribution rate case for crediting to customers. The attachment includes the deferral by rate year as well as a cumulative total in Column Z. For purposes of this response, the Company assumed new distribution base rates would take effect September 1, 2026; as such the deferral balances were forecasted through August 31, 2026.

In addition to the programs listed on Attachment PUC 7-13, Docket No. 4770 established rate allowances for other Grid Mod costs in Rate Years 2 and 3 (Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 25). Per the Amended Settlement Agreement, there are no deferrals associated with these programs if the Company's actual costs are more or less than the rate allowance for these programs. However, assuming recovery of the AMF revenue requirement begins prior to the next base distribution rate case, the Company has proposed on Schedule SAB/BLJ-1, Lines 16, 18 and 19, to reduce the AMF annual revenue requirements with the AMF related portion of the Grid Mod annual rate allowances collected in base distribution rates. For illustrative purposes, Schedule SAB/BLJ-1 reflects the reduction to the AMF revenue requirements for the amount in base rate allowances for all 20 years; however, once new base distribution rates would be effective, this adjustment to the AMF revenue requirement would not be necessary.

Revised Response:

In accordance with Paragraph 9 of the Rhode Island Public Utilities Commission's September 27, 2023 Open Meeting motions and votes, please see Compliance Attachment PUC 7-13 Revised for the forecasted deferral balances of all annual deferrals of revenue recovered in base distribution rates that arose out of rate allowances in Docket No. 4770 and that are currently in a liability position, or the Company forecasts will be in a liability position at the time of the next base distribution rate case for crediting to customers. The attachment includes the deferral by rate year as well as an actual cumulative deferral total as of August 31, 2023, in Column (p). In addition, the attachment includes on Line 6 the AMF-related portion of all other grid modernization costs identified on line 25, page 7 of 9, Compliance Attachment 1 in the Docket No. 4770 Compliance Filing (Amended Settlement Agreement Book 1) that was identified in SAB/BLJ-1.

Prepared by or under the supervision of: Stephanie A. Briggs

The Narragansett Electric Company
d/b/a Rhode Island Energy
Deferral Balances

Line No.		Rate Year Ending August 31, 2019			Rate Year Ending August 31, 2020			Rate Year Ending August 31, 2021			Rate Year Ending August 31, 2022			Rate Year Ending August 31, 2023			August 31, 2023
		Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral	Actual Cumulative Deferral
		(a)	(b)	(c)=(a)-(b)	(d)	(e)	(f)=(d)-(e)	(g)	(h)	(i)=(g)-(h)	(j)	(k)	(l)=(j)-(k)	(m)	(n)	(o)=(m)-(n)	(p) = (c)+(f)+(i)+(l)+(o)
1	AMI Business Case Study	$2,000,000	$666,667	$1,333,333	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	($1,333,333)
2	GIS Enhancements (IS)	$11,119	$142,333	($131,214)	$20,451	$142,333	($121,883)	$8,739	$142,333	($133,595)	$115,356	$142,333	($26,978)	$0	$142,333	($142,333)	($556,002)
3	Special Sector: Storage	$0	$112,586	($112,586)	$5,464	$259,668	($254,204)	$5,564	$411,986	($406,422)	$0	$411,986	($411,986)	$0	$411,986	($411,986)	($1,597,184)
4	Special Sector: Electric Transportation	$312,370	$681,300	($368,930)	$1,106,790	$1,151,751	($44,961)	$1,023,537	$2,151,776	($1,128,239)	$1,419,934	$2,151,776	($731,842)	$1,252,963	$2,151,776	($898,813)	($3,172,785)
				$0			$0			$0			$0			$0	
5	**Total**	**$2,323,489**	**$1,602,886**	**$720,603**	**$1,132,705**	**$2,220,419**	**($1,087,714)**	**$1,037,839**	**$3,372,762**	**($2,334,923)**	**$1,535,290**	**$3,372,762**	**($1,837,472)**	**$1,252,963**	**$3,372,762**	**($2,119,799)**	**($6,659,305)**
6	AMF Related Grid Mod in Base Rates		$325,733	($325,733)		$946,878	($946,878)		$1,234,459	($1,234,459)		$1,234,459	($1,234,459)		$1,234,459	($1,234,459)	($4,975,988)

Line No.		Forecasted Rate Year Ending August 31, 2024			Forecasted Rate Year Ending August 31, 2025			Forecasted Rate Year Ending August 31, 2026			Forecasted Cumulative Defereral August 31, 2026		
		Forecasted Spend	Rate Allowance	Deferral	Forecasted Spend	Rate Allowance	Deferral	Forecasted Spend	Rate Allowance	Deferral	Actual Spend	Rate Allowance	Deferral
		(q)	(r)	(s)=(q)-(r)	(t)	(u)	(v)=(t)-(u)	(w)	(x)	(y)=(w)-(x)	(z)	(aa)	(ab)=(p)+(s)+(v)+(y)
1	AMI Business Case Study	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($666,667)	$0	$666,667	($3,333,333)
2	GIS Enhancements (IS)	$0	$142,333	($142,333)	$0	$142,333	($142,333)	$0	$142,333	($142,333)	$115,356	$142,333	($983,002)
3	Special Sector: Storage	$0	$411,986	($411,986)	$0	$411,986	($411,986)	$0	$411,986	($411,986)	$0	$411,986	($2,833,142)
4	Special Sector: Electric Transportation	$936,940	$2,151,776	($1,214,836)	$776,940	$2,151,776	($1,374,836)	$755,940	$2,151,776	($1,395,836)	$1,419,934	$2,151,776	($7,158,293)
				$0			$0			$0			$0
5	**Total**	**$936,940**	**$3,372,762**	**($2,435,822)**	**$776,940**	**$3,372,762**	**($2,595,822)**	**$755,940**	**$3,372,762**	**($2,616,822)**	**$1,535,290**	**$3,372,762**	**($14,307,771)**
6	AMF Related Grid Mod in Base Rates	$0	$1,234,459	($1,234,459)	$0	$1,234,459	($1,234,459)	$0	$1,234,459	($1,234,459)	$0	$1,234,459	($8,679,365)

Line Notes:

1b, 1e, 1h	Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 26
2b, 2e, 2h	Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 27
3b, 3e, 3h	Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 36
4b, 4e, 4h	Docket No. 4770, Compliance Attachment 1, Page 7 of 9, Line 33
4p	Docket No. 4770, Electric Transportation Rate Year 5 Annual Report, Table on Page 16 of 19, Column (e)

Columns k, n, r, u, x - Rate Allowance from Rate Year August 2021 continued until next base distribution rate case

Columns a, d, g, j, m - actual revenue requirement on actual spend
Columns q, t, w - forecasted revenue requirement on forecasted spend

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Record Request No. 9 (Revised)

Request:

Please provide the Capex and Opex project implementation costs by years based on the original filing with no adjustment to scope. Please use same format as RR-5.

Original Response:

See Attachment RR-9.

Revised Response:

Please see Compliance Attachment RR-9 Revised totaling $153,217,548 Capex for project implementation. As noted on the attachment, this revision included the removal of Solar Marketplace ($664k); Carbon Footprint Calc ($166k); and C&I Multi-Fam. View ($415k). These are in the Customer Engagement line item.

This revision also included the acceleration of Sense, which is in the line item referred to as Grid Edge Comp.

Prepared by or under the supervision of: Philip J. Walnock

Removed Solar Marketplace ($664k); Carbon Footprint Calc ($166k); and C&I Multi-Fam. View ($415k). These are in Cust Engagement line item.

Sense is line item called Grid Edge Comp.

A	B	C	D	E	F
1	Systems Costs				
2	Category	Nominal ($)			
3		CapEx		OpEx	
4		Project Implementation	Year 1-4	Project Implementation	Year 1-4
5	Headend	$12,036,360	$12,036,360	$0	$3,636,715
6	MDMS	$4,439,655	$4,439,655	$0	$1,405,551
7	Cust Engagement	$2,407,000	$2,407,000	$0	$194,693
8	Analytics	$3,776,730	$3,776,730	$0	$260,261
9	Steady State Ops	$0	$0	$0	$0
10	Middleware	$2,756,563	$2,756,563	$0	$0
11	ADMS & OMS	$1,794,902	$1,794,902	$0	$0
12	Project Management	$2,800,056	$2,800,056	$0	$0
13	Cyber Security	$2,578,228	$2,578,228	$0	$0
14	CSS	$1,682,264	$1,682,264	$0	$0
15	Grid Edge Comp	$0	$0	$0	$133,202
16	Depl Exchange Mgt	$1,221,266	$1,221,266	$0	$0
17	**Total Systems Costs**	**$35,493,024**	**$35,493,024**	**$0**	**$5,630,422**
18					
19					
20					
21					
22	Meter Costs				
23	Category	Nominal ($)			
24		CapEx		OpEx	
25		Project Implementation	Year 1-4	Project Implementation	Year 1-4
26	Hardware	$68,180,106	$68,180,106	$160,500	$160,500
27	Installs	$19,031,738	$19,031,738	$0	$0
28	Pre-Sweeps	$4,400,186	$4,400,186	$0	$0
29	Project Management	$3,385,531	$3,385,531	$0	$0
30	Repairs	$0	$0	$3,022,075	$3,022,075
31	**Total Meter Costs**	**$94,997,561**	**$94,997,561**	**$3,182,575**	**$3,182,575**
32					
33					
34					
35					
36	Network Costs				
37	Category	Nominal ($)			
38		CapEx		OpEx	
39		Project Implementation	Year 1-4	Project Implementation	Year 1-4
40	Installs	$6,615,500	$6,615,500	$329,522	$329,522
41	Steady State Operations	$0	$0	$0	$0
42	Hardware	$4,891,727	$4,891,727	$0	$0
43	Project Management	$1,190,003	$1,190,003	$0	$0
44	**Total Network Costs**	**$12,697,230**	**$12,697,230**	**$329,522**	**$329,522**
45					
46					
47					
48					
49	Program Costs				
50	Category	Nominal ($)			
51		CapEx		OpEx	
52		Project Implementation	Year 1-4	Project Implementation	Year 1-4
53	Project Management	$10,029,733	$10,029,733	$0	$0
54	Change Management	$0	$0	$4,363,350	$4,363,350
55	**Total Program Costs**	**$10,029,733**	**$10,029,733**	**$4,363,350**	**$4,363,350**
56					
57					
58					
59					
60	AMF Full Deployment Costs				
61	Category	Nominal ($)			
62		CapEx		OpEx	
63		Project Implementation	Year 1-4	Project Implementation	Year 1-4
64	Systems	$35,493,024	$35,493,024	$0	$5,630,422
65	Meters	$94,997,561	$94,997,561	$3,182,575	$3,182,575
66	Network	$12,697,230	$12,697,230	$329,522	$329,522
67	Program	$10,029,733	$10,029,733	$4,363,350	$4,363,350
68	**Total AMF Costs**	**$153,217,548**	**$153,217,548**	**$7,875,447**	**$13,505,869**