Rhode Island Energy

The Narragansett Electric Company

FY 2022 Electric Infrastructure, Safety and Reliability Plan

Annual Reconciliation

August 1, 2022

Docket No. 5098

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-7263

Rhode Island Energy™
a PPL company

August 1, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 5098 - FY 2022 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please see the Company's Annual Reconciliation for the Fiscal Year ("FY") 2022[1] Electric Infrastructure, Safety, and Reliability ("ISR") Plan (this "Filing" or "Reconciliation Filing"). This Filing is being submitted to the Public Utilities Commission ("PUC") in accordance with R.I. Gen. Laws § 39-1-27.7.1(c) and Sections (I)(B) and (IV) the Infrastructure, Safety, And Reliability Provision, R.I.P.U.C. No. 2199 (the "ISR Provision"). This Filing consists of the following documents:

- **Pre-Filed Direct Testimony of Patricia C. Easterly -** The testimony of Ms. Easterly presents the Filing in relation to the FY 2022 Electric ISR Plan which was approved by the PUC in this docket. Attachment PCE-1, which is attached to Ms. Easterly's testimony, includes an Executive Summary, FY 2022 Plant in Service Additions, FY 2022 Capital Spending Summary, FY 2022 Capital Spending by Key Driver Category, FY 2022 Vegetation Management ("VM"), FY 2022 Other Operations and Maintenance ("O&M"), and Reliability Performance. See below for summary:

Item	Target/Budget	Actual
Plant in Service Additions	$98.5M	$88.8M
Cost of Removal Spending	$14.6M	$7.7M
Capital Spending	$101.6M	$106.7M
O&M Spending	$12M	$12.1M

[1] For purposes of this filing, FY 2022 is April 1, 2021 through March 31, 2022.

- **<u>Joint Pre-Filed Direct Testimony of Stephanie A. Briggs and Jeffrey D. Oliveira</u>** – The joint testimony of Ms. Briggs and Mr. Oliveira describes the calculation of the revenue requirement. The revenue requirement totals $37,760,618. This is a decrease of $3,597,101 from the projected FY 2022 Electric ISR revenue requirement of $41,357,719, previously approved by the PUC in this docket.

- **<u>Pre-Filed Direct Testimony of Peter R. Blazunas</u>** – The testimony of Mr. Blazunas presents the proposed CapEx and O&M Reconciling Factors, as those terms are defined in the ISR Provision, resulting from the reconciliation of actual costs and revenue associated with the FY 2022 ISR Plan. The impact of the proposed CapEx Reconciling Factor of ($0.00089) per kWh and the proposed O&M Reconciling Factor of $0.00000 per kWh on a typical residential customer receiving Last Resort Service and using 500 kWh per month is a decrease of $0.06, or approximately 0.1%, from $111.15 to $111.09.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5098 Service List
Leo Wold, Esq., Division
John Bell, Division

PRE-FILED DIRECT TESTIMONY

OF

PATRICIA C. EASTERLY

August 1, 2022

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I. Introduction and Qualifications

Q. Ms. Easterly, please state your name and business address.

A. My name is Patricia C. Easterly. My business address is 280 Melrose St., Providence Rhode Island 02907.

Q. Ms. Easterly, by whom are you employed and in what position?

A. I am employed by Rhode Island Energy as Senior Manager Performance and Financial Planning and Analysis. In my position, I am responsible for the performance management and financial planning for the RI Energy business.

Q. Ms. Easterly, please describe your educational background and professional experience.

A. In 1983, I earned a Bachelor of Arts degree in Finance from Simmons College. In October 1983, I joined Peat, Marwick, and Mitchell in St. Louis, Missouri, as a staff auditor, progressing to senior auditor and becoming a Certified Public Accountant in the State of Missouri. In November 1987, I joined Edison Brothers Stores in St. Louis as Assistant Controller. In June 1988, I joined NGSC as a financial analyst in the Accounting division. Since that time, I have held various positions within National Grid, including Manager of Accounting, Director of Internal Audit, Transmission Finance Director, Distribution Finance Director, Director Rhode Island – New Energy Solutions Planning, Budget and Performance, and Director for Finance Performance Management program and Director – New England

Electric Performance and Strategy. Effective May 25, 2022, I assumed my current position as Senior Manager Performance and Financial Planning and Analysis.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?

A. Yes. I have previously testified before the PUC in support of the Company's FY 2023 Electric Infrastructure, Safety and Reliability (ISR) Plan in Docket 5209, FY 2022 Electric Infrastructure, Safety and Reliability Plan in Docket No. 5098, FY 2021 Electric ISR Plan in Docket No. 4995, FY 2020 Electric ISR Plan in Docket No. 4915, and FY 2019 Electric ISR Annual Reconciliation in Docket No. 4783. In addition, I have testified before the PUC in support of the Company's Rhode Island Storm Contingency Fund.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company's FY 2022 Annual Reconciliation filing related to the FY 2022 Electric ISR Plan approved by the PUC in this docket. This filing provides the actual plant in service for discretionary and non-discretionary capital investment and associated cost of removal (COR), the actual vegetation management (VM) operation and maintenance (O&M) expenses, and the actual inspection and maintenance (I&M) program and other O&M expenses for the period April 1, 2021 to March 31, 2022. As described in Ms. Stephanie Briggs and

Mr. Jeffrey Oliveira's Joint testimony in this filing, the plant in service investment and the O&M expenses are used to calculate the FY 2022 Electric ISR Plan revenue requirement. As explained in Mr. Peter Blazunas' testimony in this filing, the annual capital investment revenue requirement on the actual cumulative ISR capital investment and the actual O&M expense incurred is then reconciled against the actual revenue billed during FY 2022. Specific details by category for the FY 2022 Electric ISR Plan plant-in-service additions, associated COR, and actual capital spending are included in Attachment PCE-1, which is attached to this testimony.

III. Plant In Service and Cost of Removal

Q. Please provide an overview of the plant in service and cost of removal for FY 2022.

A. As shown in Table 2 of Attachment PCE-1, in FY 2022, plant additions of $88.8 million were placed in service. This amount was approximately $9.7 million under the target of $98.5 million. Non-Discretionary plant additions totaling $46.6 million were placed in service, which was $5.9 million over the target of $40.7 million. This variance was due to more plant additions related to failed assets and storms. Discretionary plant additions totaling $42.2 million were placed in service, which was $15.6 million under the planned amount of $57.8 million. This was primarily driven by the timing of the actual Large Project plant additions compared to the timing and amounts targeted.

As shown in Table 3 of Attachment PCE-1, the associated cost of removal was $7.7 million which was under-budget by $6.9 million from the FY 2022 target of $14.6 million.

These totals resulted in an Electric ISR Plan investment of $96.5 million, which was $16.6 million under the Company's target of $113.1 million. Additional details on these variances are included in Section I of Attachment PCE-1.

IV. Capital Spending

Q. Please summarize the Company's actual capital spending for FY 2022 for the Electric ISR Plan.

A. As shown in Table 4 of Attachment PCE-1, the Company spent $106.7 million for capital investment under the Electric ISR Plan. This amount was $5.1 million over the annual approved budget of $101.6 million. Non-discretionary capital spending included under spending on meter purchases, meter work, and public requirements projects. This was offset by spending related to Distributed Generation (DG) projects and major storm work.

For FY 2022, capital spending in the Discretionary sub-category (excluding large projects) was $36.7 million, which was $5.3 million under the annual approved budget of $42.0 million. This was driven primarily by underspending on major projects offset by lower spending in programs including I&M, 3V0, EMS and VVO.

In FY 2022, the Southeast Substation, Dyer Street Substation and Providence Study projects were reported on separately from other Asset Condition projects. Capital spending was $15.5 million, which was $4.6 million under the annual approved budget of $20.2 million.

The key drivers and variances by category are discussed in more detail in Section III of Attachment PCE-1.

V. O&M Spending

Q. Please summarize the Company's actual O&M spending for the FY 2022 Electric ISR Plan.

A. Total O&M spending was $12.1 million as compared to a budget of $12.0 million. As shown in Table 10 of Attachment PCE-1, for FY 2022, the Company's vegetation management O&M spending was $11.3 million, which was over-budget by $0.5 million. In addition, as shown in Table 11, the Company's Other O&M spending related to the I&M and Volt/VAR Optimization and Conservations Voltage Reduction (VVO/CVR) programs was $0.8 million, which was $0.4 million under the approved O&M budget of $1.2 million. Detailed information regarding the work completed are discussed in Attachment PCE-1 in Section IV and Section V, respectively.

VI. Reliability Performance

Q. Please summarize the results of the Company's reliability performance for CY 2021.

A. Section VI of Attachment PCE-1 includes the Company's Reliability Performance for calendar year 2021 (CY 2021). The Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2021, with SAIFI of 0.949 against a target of 1.05, and SAIDI of 68.8 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days.[1]

Q. Please provide an update on the Company's review of DG projects.

A. As stated in the March 9, 2022 hearing, the Company has undertaken a review of DG projects including how capital contributions for projects are allocated by cost type, identifying what drove cost variances from estimates, and the processes that support these items. We had initially planned to complete the review and report the results to the Commission by August 1, 2022. Although good progress has been made, additional time will be required to complete the review. The Company's updated target date for completion of the review is October 1, 2022. Based on preliminary project work, an adjustment of $391,000 has been made through this reconciliation filing to remove plant additions from rate base. When the review is completed, a summary of all results will be provided and any additional adjustment amounts identified after the filing of this testimony but before October 1st will be communicated to the Division and Commission and based on timing, will be factored into the new rates effective October 1, 2022.

[1] A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (6.67 minutes for CY 2021). For purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.

Q. Please explain the Company's position on the Dyer Street pre-construction costs

A. In response to Record Request 2 from the hearing in Docket 5209,[2] the Company estimated that approximately $0.855 million of the Dyer Street project costs relate to the DC building. As of March 31, 2022, no assets associated with this project placed in service are included in the revenue requirement. The Company respectfully requests additional time to evaluate these costs against the regulatory prudence principle and proposes to address the costs during the FY 2023 ISR Plan reporting year, before the project goes into service.

Q. Does this conclude your testimony?

A. Yes.

[2] See https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5209-NGrid-Electric-ISR-FY2023-RRs-%28PUC-3-22-22%29.pdf

Attachment PCE-1

FY 2022 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation Filing

FY 2022 Electric Infrastructure, Safety and Reliability Plan
Annual Reconciliation Filing

EXECUTIVE SUMMARY

In accordance with its tariff, RIPUC No. 2199, Sheets 1-5, The Narragansett Electric Company d/b/a Rhode Island Energy ("Company") submits this Annual Reconciliation Filing for the FY 2022 Electric Infrastructure, Safety and Reliability Plan approved by the Rhode Island Public Utilities Commission (PUC) in Docket No. 5098. This filing provides the actual capital spending and operation and maintenance (O&M) spending for the period April 1, 2021 through March 31, 2022. In addition, actual Plant in Service Additions and Cost of Removal are compared to targets for discretionary and non-discretionary categories. Finally, this filing includes a summary of the Company's reliability performance through December 31, 2021. Table 1 summarizes the FY 2022 program.

Table 1
FY 2022 ISR Activity

FY 2022 *in millions $*	**Target / Budget**	**Actuals**	**Variance Over / (Under)**
Plant in Service Additions - Non-discretionary	$40.7	$46.6	$5.9
Plant in Service Additions - Discretionary	$57.8	$42.2	($15.6)
Plant in Service Additions	**$98.5**	**$88.8**	**($9.7)**
Cost of Removal Spending - Non-discretionary	$4.9	$4.0	($1.0)
Cost of Removal Spending - Discretionary	$9.7	$3.8	($5.9)
Cost of Removal Spending	**$14.6**	**$7.7**	**($6.9)**
Capital Spending - Non-discretionary	$39.4	$54.5	$15.1
Capital Spending - Discretionary	$62.2	$52.2	($10.0)
Capital Spending	**$101.6**	**$106.7**	**$5.1**
Vegetation Management Spending	$10.8	$11.3	$0.5
I&M and Other O&M Spending	$1.2	$0.8	($0.4)
O&M Spending	**$12.0**	**$12.1**	**$0.1**

This filing includes testimony from Ms. Briggs, Mr. Oliveira, and Mr. Blazunas. Ms. Briggs' and Mr. Oliveira's joint testimony describes the calculation of the revenue requirement based on the capital plant-in-service and the total annual actual VM and O&M expenses for the fiscal year. Their testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. As shown in Ms. Briggs' and Mr. Oliveira's joint testimony, for the FY 2022 filing, the Company has an updated revenue requirement of $37.8 million.

Mr. Blazunas' testimony provides a description of the reconciliation of the final actual FY 2022 revenue requirement against revenue billed in support of that revenue requirement, the proposed factors resulting from the reconciliation, and the bill impacts of those proposed factors. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Last Resort Service and using 500 kWhs per month is a decrease of $.06, or approximately 0.1% from $111.15 to $111.09.

I. FY 2022 Plant in Service Additions

As shown in Table 2 below, in FY 2022, plant additions of $88.8 million were placed in service, which was $9.7 million under the target amount of $98.5 million. Non-discretionary plant additions totaling $46.6 million were placed in service, which was $5.9 million over the target of $40.7 million. This increase was due to more plant additions associated with failed assets and storms. Discretionary plant additions totaling $42.2 million were placed in service, which were $15.6 million under the planned amount of $57.8 million. This was primarily driven by the timing of the actual Large Project plant additions compared to the timing and amounts targeted. Dyer Street Substation, New Lafayette Substation, and the Providence Study projects were less due to delays. Less plant was placed in service for the Aquidneck Island project due to lower actual costs than estimated and some work was completed in FY 2021.

Table 2
Plant Additions by Category

	Target	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$25,830,428	$25,316,707	($513,720)
Damage Failure	$14,837,522	$21,245,565	$6,408,043
Non-Discretionary Sub-total	*$40,667,949*	*$46,562,272*	*$5,894,322*
Asset Condition	$39,096,970	$29,872,380	($9,224,589)
Non-Infrastructure	$1,101,664	$805,972	($295,692)
System Capacity & Performance	$17,620,340	$11,522,078	($6,098,263)
Discretionary Sub-total	*$57,818,974*	*$42,200,430*	*($15,618,544)*
Total Plant Additions	**$98,486,924**	**$88,762,701**	**($9,724,222)**

The variances shown in Table 2 reflect the timing of when plant is placed into service. In general, once equipment is energized and placed into service to support electric load, capital costs are transferred from FERC Account 107 (Construction Work in Progress or CWIP) to FERC Account 106 (Plant in Service), which is when the underlying capital work becomes used and useful in the service of customers. This can differ by the type of plant and facility. For example, electric distribution line equipment is normally placed in service closer to the time it is installed because it is typically energized at that time and begins to support electric load, and therefore, is used and useful in the service of customers. Because electric distribution line equipment is typically energized as it is installed, a relatively significant amount of plant is placed into service as work progresses. By contrast, substation construction typically involves multi-year projects. The assets must pass testing, the work must be commissioned, and the assets must be energized before being placed in service. Because substation construction is typically completed in one or more phases as part of a multi-year process, the assets will only be placed in service to serve customers once all work in a phase is completed.

Table 3 provides the total Cost of Removal (COR) for FY 2022, which was $7.7 million, $6.9 million under the forecast of $14.6 million. Non-discretionary COR spending was $4.0 million, which was $0.9 million under the planned amount of $4.9 million, primarily due to proceeds from street light sales. COR associated with Discretionary work totaled $3.8 million, which was $5.9 million under the annual planned amount of $9.7 million, similar to plant in service primarily due the timing of the large projects identified in the previous section and removal work related to the Pawtucket 1 substation retirement (Southeast Substation) that was lower than estimated due to delays into future years.

Table 3
COR by Category

	Target	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$2,966,000	$1,127,100	($1,838,900)
Damage Failure	$1,942,000	$2,825,208	$883,208
Non-Discretionary Sub-total	*$4,908,000*	*$3,952,308*	*($955,692)*
Asset Condition	$6,927,190	$2,315,049	($4,612,141)
Non-Infrastructure	$23,000	$808	($22,192)
System Capacity & Performance	$2,741,835	$1,475,822	($1,266,013)
Discretionary Sub-total	*$9,692,025*	*$3,791,678*	*($5,900,347)*
Total Capital Investment in System	**$14,600,025**	**$7,743,986**	**($6,856,039)**

II. FY 2022 Capital Spending Summary

As shown in Table 4 below, capital spending for FY 2022 totaled $106.7 million, which was $5.1 million over the FY 2022 budget of $101.6 million.

Table 4
Capital Spending by Category

	Budget	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$27,237,000	$34,334,178	$7,097,178
Damage Failure	$12,198,000	$20,200,300	$8,002,300
Non-Discretionary Sub-total	*$39,435,000*	*$54,534,478*	*$15,099,478*
Asset Condition	$20,329,612	$20,278,731	($50,881)
Non-Infrastructure	$1,309,600	$1,100,074	($209,526)
System Capacity & Performance	$20,373,460	$15,302,811	($5,070,649)
Discretionary Sub-total (excl. Large Projects)	*$42,012,672*	*$36,681,616*	*($5,331,056)*
Large Projects Tracked Separately	$20,152,678	$15,512,977	($4,639,701)
Discretionary Sub-total	*$62,165,350*	*$52,194,593*	*($9,970,757)*
Total Capital Investment in System	**$101,600,350**	**$106,729,071**	**$5,128,721**

III. FY 2022 Capital Spending by Key Driver Category

1. Non-Discretionary Spending

a. Customer Request/Public Requirement

Capital spending for FY 2022 in the Customer Request/Public Requirement category was approximately $34.3 million, which was $7.1 million over the FY 2022 budget of $27.2 million. The major drivers of this variance are:

- Spending on Third-Party Attachment projects was under budget by $0.2 million at year end. Customer advances were collected at the end of the fiscal year for work that will be completed in FY 2023, resulting in the underspending variance of $0.2 million at fiscal year-end.
- Net spending activity in the Distributed Generation (DG) category was $8.8 million over budget for the fiscal year. As stated in the March 9, 2022 hearing, the Company has undertaken a review of DG projects, which is in progress. As noted in the testimony the review includes how capital contributions for projects are allocated by cost type, identifying what drove cost variances from estimates, and the processes that support these items. The FY 2022 spending will also be reviewed in a similar manner. The Company's updated target date for completion of the review is October 1. Approximately $4.2 million of the spending over budget is due to timing differences of when contributions that have been received are offset against capital spending. The remainder primarily relates to $4.2 million for a substation project, some of which has been completed, put into service, recently reconciled and additional invoices will be sent to the customer for the additional spending. The remainder is still under construction and will be reconciled at a later date. Spending for this substation project as well as other DG projects in FY 2022 will also be reviewed similar to the DG project underway.
- Spending for meter purchases was under budget $0.4 million due to vendor manufacturing and delivery delays and longer lead times throughout the year. The remainder of the Meter spending category was under budget by $0.6 million due to efforts to complete the Meter Reprogramming project which required minimal capital spending during FY 2022 but resulted in the deferral of the Landline Meter Replacement project until FY 2023.
- Current year billings associated with a joint-owned pole agreement were included in the New Business-Residential spending category and were under budget by $0.7 million.

- New Business-Commercial spending was $0.7 million under budget at year end. Blanket project spending was $0.7 million under budget and spending on specific projects was in line with the budgeted reserve.
- Capital spending on Public Requirements projects was $1.0 million under budget as of March 31, 2022 due to spending on specific projects being less than estimated.
- Capital spending for transformers was $0.7 million over budget. Supply chain challenges continue to impact both the price and quantity of purchases. These include extended lead times, demand exceeding capacity, raw material shortages, and logistical constraints. During FY 2022, the Company sought alternate sources of supply, placed proactive orders to mitigate future supply gaps, and increased inventory levels to support work plans and respond to emergencies.

Detailed budget and actual spending by budget classification for the Customer Request/Public Requirement category is shown in Table 5 below.

Table 5
Customer Request/Public Requirement Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	Third-party Attachments	$281,000	$102,985	($178,015)
	Distributed Generation	$1,000,000	$9,800,831	$8,800,831
	Land and Land Rights	$393,000	$513,125	$120,125
	Meters – Distribution	$3,375,000	$2,350,861	($1,024,139)
	New Business – Commercial	$9,066,000	$8,330,547	($735,453)
	New Business – Residential	$4,020,000	$4,691,058	$671,058
	Outdoor Lighting	$577,000	$617,341	$40,341
	Public & Regulatory Requirement	$2,960,000	$1,936,666	($1,023,334)
	Transformers & Related Equipment	$4,915,000	$5,631,462	$716,462
	Strategic DER Investments	$650,000	$364,796	($285,204)
	Customer Request/Public Requirement Spending	**$27,237,000**	**$34,339,672**	**$7,102,672**

b. Damage/Failure

Capital spending in the Damage/Failure category was $20.2 million, which was $8.0 million over the FY 2022 budget of $12.2 million. This variance was driven by the following:

- Actual storm costs during FY 2022 of $7.8 million exceeded budgeted storm costs by $6.0 million. August's Tropical Storm Henri and the October 26, 2021 Nor'easter event were the more significant weather events.
- The Company continues to review Damage/Failure work each month as it categorizes failed asset work only in the Damage/Failure category of the Non-Discretionary portfolio and all other work in the Asset Condition category of the Discretionary portfolio. Spending under the blanket projects was $11.0 million, $1.4 million over budget.
- A reserve of $0.9 million is included in the budget to cover the failure of large assets. During FY 2022, the Company had three asset failures.

    - In May 2021, the Westerly #2 Transformer failed and was removed from service. In July, a spare transformer was installed. Capital spending totaled $0.9 million.
    - Replacement on the 3763 Line of a failed concrete pole and structure with a light duty steel structure. Capital spending totaled $0.3 million.
    - Replacement at Gate II substation of failed potential transformers and foundations. Capital spending totaled $0.3 million.

Detailed budget and actual spending for the Damage/Failure category is shown in Table 6 below.

Table 6
Damage/Failure Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Damage/Failure	Damage/Failure	$10,448,000	$12,441,308	$1,993,308
	Major Storms	$1,750,000	$7,758,992	$6,008,992
	Damage/Failure Spending	**$12,198,000**	**$20,200,300**	**$8,002,300**

2. Discretionary Spending

a. *Asset Condition (without Separately Tracked Large Projects)*

Capital spending in the Asset Condition category excluding Large Projects was $20.3 million, which was essentially on the $20.3 million FY 2022 budget. The following projects and programs were included in this category of spending:

- Capital spending on URD projects was $5.6 million, over budget by $0.9 million. The majority of the overage related to a specific URD project that required special equipment for ledge removal and additional labor to complete the work.

- Underground Cable Replacement program spending is $0.3 million over the budget of $5.0 million primarily due to continuation of work in critical downtown Providence areas. Work on the UG Cable Replacement project at Charles & Orms Streets is essentially completed and went into service during FY 2022.
- The Asset Replacement Blanket projects were approximately $0.6 million over budget in FY 2022. The FY 2022 and FY 2021 budgets for Asset Replacement Blanket and I&M were considered together and each increased by $1.0 million pending the implementation of the Damage/Failure processes. The Company believes that the current level of blanket spending is more indicative of ongoing requirements and therefore proposed an increase in the FY 2023 Plan to accommodate this expectation.
- Capital spending on I&M was $1.3 million, $1.7 million under budget due to the streamlined program's focus on addressing priority and backlog work and should also be considered in combination with the Asset Replacement Blanket due to how the FY 2021 and FY 2022 budgets were set.
- Capital spending on the Franklin Square Breaker Replacement project was $0.7 million under budget as of March 31, 2022. Spending associated with the installation of the breakers was delayed due to the lack of vendor availability and will shift to FY 2023.
- Capital spending on the Franklin Square 11kV Substation project continued from FY 2021 and totaled $1.5 million during FY 2022. This project is associated with the Transmission project taking place at the Franklin Square Substation. The distribution project scope included a new outdoor 11 kV riser structure, removal of existing 11kV cable during coordinated outages and installation of new 11kV cable. Minimal budget for this project was included in the FY 2022 Plan because requirements were identified after the budget was set. The project is complete and was placed into service.

b. <u>Asset Condition – Separately Tracked Large Projects</u>

During FY 2022, capital spending on the Southeast Substation, Dyer Street Substation and Providence Area projects in the Asset Condition category was $15.5 million, $4.6 million under the budget of $20.2 million.

- Capital spending on the Southeast Substation project was $2.9 million, $0.8 million over the $2.1 million budget. The remaining portion of the substation and the majority of the distribution line went into service during FY 2022. Work on the Pawtucket substation retirement will continue into FY 2023.
- Capital spending on Dyer Street substation was $5.1 million, $4.6 million under the $9.7 million budget. The project was under budget due to delays in material deliveries. Work shifted into FY 2023 has been reflected in the proposed FY 2023 ISR Plan.

- Capital spending on the Providence Area Study projects (Admiral Street projects) was $7.5 million, $0.9 million under the budget of $8.4 million.

For additional information on specific large project variances, please see Attachment G to the Company's FY 2022 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2022 (Docket 5098) filed with the PUC on May 13, 2022. A copy of this report is attached as Attachment 1. Detailed budget and actual spending by budget classification for the Asset Condition category is shown in Table 7 below.

Table 7
Asset Condition Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Asset Condition	Asset Replacement	$17,329,612	$18,965,212	$1,635,601
	Asset Replacement – Large Projects	$20,152,678	$15,512,977	($4,639,701)
	Asset Replacement - I&M	$3,000,000	$1,313,519	($1,686,481)
	Asset Condition Spending	**$40,482,289**	**$35,791,708**	**($4,690,581)**

c. Non-Infrastructure

Capital spending for the Non-Infrastructure category was $1.1 million, which was $0.2 million under the FY 2022 budget of $1.3 million. The primary driver of the underspend relates to the resequencing of work required by a third party for the Copper to Fiber Conversion project. The variance in Corp Admin is attributed to accounting overhead charges of $0.4 million. These charges will be transferred from the Non-Infrastructure category to the appropriate work orders through the normal capital allocation process during FY 2023.

Detailed budget and actual spending for the Non-Infrastructure category is shown in Table 8 below.

Table 8
Non-Infrastructure Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
Non-Infrastructure	Corporate/Admin/General/Other	$0	$380,856	$380,856
	General Equipment	$250,000	$457,629	$207,629
	Telecommunications	$259,600	$101,770	($157,830)
	Copper to Fiber Conversions	$800,000	$159,819	($640,182)
	Non-Infrastructure Spending	**$1,309,600**	**$1,100,074**	**($209,526)**

d. ***System Capacity & Performance***

Capital spending for FY 2022 for the System Capacity and Performance category was $15.3 million, which was $5.1 million under the FY 2022 budget of $20.4 million. This variance was driven primarily by the following projects:

- Capital spending on the Aquidneck Island projects was $3.9 million which was $2.5 million under the budget of $6.4 million. Drivers include FY 2022 work shifts to FY 2021, removal of contingencies, and actuals coming in less than estimates.
- Capital spending on New Lafayette substation project was $2.3 million which was $0.4 million over the budget of $1.9 million due to the continued acceleration of civil work to coordinate with a Distributed Generation project taking place on the same site.
- Capital spending on the East Providence and Warren substation projects was $0.9 million under budget due to project delays.
- Capital spending on VVO projects was $2.6 million, $0.6 million under budget. The primary driver of the underspend relates to a distribution line project that has been shifted to FY 2023.
- Capital spending on EMS projects was $0.8 million, $0.5 million under budget. FY 2022 capital spending was reduced to align with the results of area studies.
- Capital spending on 3V0 projects was $0.4 million, $1.1 million under budget due to the removal of projects from the FY 2022 Plan impacted by future retirements.
- Capital spending on projects related to COVID load shifts was $0.9 million, $1.1 million under budget. Work on the 59F3 and 72F5 Lines, along with some smaller blanket level work, will be completed in FY 2023. Until the

work is completed, the Company continues to monitor load and will take immediate action to manage the system safely and reliably.

- Included in the System Capacity & Performance category of capital spending is $0.8 million of preliminary survey and investigation ("PS&I") costs associated with Area Studies. Once the Area Studies' capital projects are established, these PS&I costs will be reclassified and distributed to the capital projects.

Detailed budget and actual spending for the System Capacity & Performance category is shown in Table 9 below.

Table 9
System Capacity & Performance Capital Spending

Category	Budget Classification	Budget	Actuals	Variance Over / (Under)
System Capacity & Performance	Load Relief	$10,921,616	$7,269,686	($3,651,930)
	Reliability	$9,451,844	$8,033,126	($1,418,718)
	System Capacity & Performance Spending	**$20,373,460**	**$15,302,811**	**($5,070,649)**

IV. FY 2022 Vegetation Management (VM)

For FY 2022, the Company completed 1,376 miles of distribution cycle pruning at a cost of $11.3 million. The Company completed 100% of its work plan for FY 2022. Table 10 below provides the spending components. The increase in spending is due to increased police costs, increased costs to respond to customer requests for trouble work, and slight increases in pockets of poor performance to complete the work plan, which also correlate to responding to the increasing level of outages caused by tree events. Cost challenges are expected to continue, and the Company is exploring ways to minimize these impacts, such as a strategy to move to tree risk modeling, as well as modifying vendor contracts.

Table 10
Vegetation Management O&M Spending

	Budget	Actuals	Variance Over / (Under)
Cycle Pruning (Base)	$6,600,000	$6,540,028	($59,972)
Hazard Tree	$1,500,000	$1,542,884	$42,884
Sub-T (on & off road)	$500,000	$480,709	($19,291)
Police/Flagman Details	$775,000	$872,630	$97,630
Pockets of Poor Performance	$200,000	$234,616	$34,616
Core Crew (all other activities)	$1,225,000	$1,590,696	$365,696
Total VM O&M Spending	**$10,800,000**	**$11,261,563**	**$461,563**

V. FY 2022 Other Operations and Maintenance (O&M)

For FY 2022, the Company completed 100% of its annual overhead structure inspection goal with an associated spend of $0.5 million. Table 11 below provides the spending components in the Other O&M category.

Table 11
Other O&M Spending

	Budget	Actuals	Variance Over / (Under)
Opex Related to Capex	$421,000	$149,379	($271,621)
Repair & Inspections Related Costs	$475,000	$462,554	($12,446)
System Planning & Protection Coordination Study	$25,000	$0	($25,000)
VVO/CRV Program	$262,000	$207,507	($54,493)
Total I&M O&M Spending	**$1,183,000**	**$819,440**	**($363,560)**

For additional information about the I&M program, please see the Company's FY 2022 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2022 (Docket 5098) filed with the PUC on May 13, 2022. A copy of this report is attached as Attachment 1.

VI. Reliability Performance

The Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2021, with SAIFI of 0.949 against a target of 1.05, and SAIDI of 68.8 minutes, against a target of 71.9 minutes. For additional information on reliability and major event days, please refer to the 2021 Service Quality Report filed under Docket 3628 on April 29, 2022. A copy is attached to this report as Attachment 2.

Attachment 1

Quarterly Report for the Fourth Quarter Period Ending March 31, 2022

nationalgrid

Andrew S. Marcaccio
Senior Counsel

May 13, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 5098 – FY2022 Electric Infrastructure, Safety, and Reliability Plan
Quarterly Update – Fourth Quarter Ending March 31, 2022

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed an electronic version of the Company's fiscal year (FY) 2022 Electric Infrastructure, Safety, and Reliability (ISR) Plan quarterly update for the fourth quarter ending March 31, 2022.[2] Pursuant to the provisions of the approved FY 2018 Electric ISR Plan, the Company committed to providing quarterly updates on the progress of its Electric ISR program to the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-4263.

Very truly yours,

Andrew S. Marcaccio

Enclosures

cc: Docket 5098 Service List
Tiffany Parenteau, Esq.
John Bell, Division
Greg Booth, Division

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[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

[2] Per a communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Andrew S. Marcaccio

May 13, 2022
Date

Docket No. 5098 - National Grid's Electric ISR Plan FY 2022
Service List as of 4/1/2021

Name/Address	**E-mail Distribution**	**Phone**
Andrew.Marcaccio, Esq. Jennifer Hutchinson, Esq. **National Grid** 280 Melrose St. Providence, RI 02907	Andrew.Marcaccio@nationalgrid.com; jennifer.hutchinson@nationalgrid.com; celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com;	401-784-7288
National Grid Melissa Little Patricia Easterly Kathy Castro Susan Toronto Ryan Constable William Richer	Melissa.Little@nationalgrid.com; Patricia.easterly@nationalgrid.com; Kathy.Castro2@nationalgrid.com; Susan.Toronto@nationalgrid.com; Ryan.Constable@nationalgrid.com; William.Richer@nationalgrid.com;	
Division of Public Utilities (Division) Christy Hetherington, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	christy.hetherington@dpuc.ri.gov; Dmacrae@riag.ri.gov; MFolcarelli@riag.ri.gov; John.bell@dpuc.ri.gov; Joseph.shilling@dpuc.ri.gov; Margaret.l.hogan@dpuc.ri.gov; Linda.george@dpuc.ri.gov; Robert.Bailey@dpuc.ri.gov;	
David Effron Berkshire Consulting 12 Pond Path North Hampton, NH 03862-2243	Djeffron@aol.com;	603-964-6526

Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440
Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	Lkushner33@gmail.com;	919-810-1616
Office of Energy Resources (OER) Albert Vitali, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Albert.Vitali@doa.ri.gov;	401-222-3417
	Nancy.Russolino@doa.ri.gov;	
	Christopher.Kearns@energy.ri.gov;	
	Nicholas.Ucci@energy.ri.gov ;	
	Carrie.Gill@energy.ri.gov ;	
File an original & five (5) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov;	401-780-2107
	John.harrington@puc.ri.gov;	
	Cynthia.WilsonFrias@puc.ri.gov;	
	Todd.bianco@puc.ri.gov;	
	Emma.rodvien@puc.ri.gov;	
	Alan.nault@puc.ri.gov;	
PPL Electric Utilities Ronald Reybitz Stephen Breininger	rjreybitz@pplweb.com;	
	skbreininger@pplweb.com;	
Matthew Sullivan, Green Development	ms@green-ri.com;	

Electric Infrastructure, Safety, and Reliability Plan
FY 2022 Quarterly Update
For the Fiscal Year Ending March 31, 2022

EXECUTIVE SUMMARY

As shown in Attachment A during the fiscal year ending March 31, 2022, the Company[1] spent $106.7 million for capital projects against a budget of $101.6 million. Non-Discretionary spending was $54.5 million, $15.1 million over the budget of $39.4 million. Discretionary spending, including the separately tracked large projects, was $52.2 million, $10.0 million under the budget of $62.2 million. Spending in each of these categories is addressed in more detail below.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

I. FY 2022 Capital Spending by Key Driver Category

1. <u>Non-Discretionary Spending</u>

a. <u>Customer Request/Public Requirement</u>

During FY 2022, capital spending in the Customer Request/Public Requirement category was $34.3 million, which was $7.1 million over the FY 2022 budget of $27.2 million. The major drivers are:

- Spending on Third-Party Attachment projects was under budget by $0.2 million at year end. Additional customer advances were collected in February and March for work that will be completed in FY 2023, resulting in the underspending variance of $0.2 million.

- Net spending activity in the Distributed Generation (DG) category was $8.8 million over budget for the fiscal year. As stated in the March 9, 2022 hearing, the Company has undertaken a review of DG Projects and will report the results to the Commission by August 1, 2022.

- Public requirements spending was $1.0 million under budget as of March 31, 2022 due to specific projects being less than estimated.

- New Business-Commercial spending was $0.7 million under budget as of March 31, 2022. Spending under the blanket project was $0.7 million under budget and spending on specific projects was in line with the budgeted reserve.

- Current year billings associated with a joint-owned pole agreement were included in the New Business-Residential spending category and were under budget by $0.7 million

- Spending for meter purchases was under budget $0.4 million due to vendor manufacturing and delivery delays and longer lead times throughout the year. The remainder of the Meter spending category was under budget by $0.6 million due to efforts to complete the Meter Reprogramming project which required minimal capital spending during FY 2022. The Landline Meter Replacement project was deferred to FY 2023.

- Capital spending for transformers was $5.6 million, $0.7 million over the budget of $4.9 million. Supply chain challenges continue that have impacted both the price and quantity of purchases, which include extended lead times, demand exceeding capacity, raw material shortages, and logistical constraints. During FY 2022, the Company sought alternate sources of supply, placed proactive orders to mitigate future supply gaps, and increased inventory levels (stocking points, safety stock and emergency quantity) to support work plans and respond to emergencies.

- Capital spending for the Strategic DER projects was $0.3 million under budget. Construction on the feeder monitors at Chopmist substation is complete. Construction was completed for two feeder monitors at Hopkins Hill substation during FY 2022. The remaining feeder monitors will be completed in FY 2023. The design of full implementation of advanced devices at Chopmist substation is approximately 65% complete. The Company expects to complete the design and implementation in alignment with a grid modernization plan.

b. ***Damage/Failure***

During FY 2022, capital spending in the Damage/Failure category was $20.2 million, which was $8.0 million over the FY 2022 budget of $12.2 million. The primary drivers are:

- Actual storm costs during FY 2022 of $7.8 million exceeded budgeted storm costs by $6.0 million. August's Tropical Storm Henri and the October 26, 2021 Nor'easter event were the more significant weather events.

- The Company continues to review Damage/Failure work each month as it transitions to categorizing only work related to failed assets in the Damage/Failure category of the Non-Discretionary portfolio and all other work in the Asset Replacement category of the Discretionary portfolio. Spending under the blanket projects was $11.0 million, $1.4 million over budget.

- Costs for failures related to large projects was $0.6 million over budget due to two replacement projects that took place during FY 2022. The projects included the replacement on the 3763 Line of a concrete pole and structure with a light duty steel structure and the replacement at Gate II substation of potential transformers and foundations.

2. <u>Discretionary Spending</u>

a. <u>Asset Condition (without Separately Tracked Large Projects)</u>

During FY 2022, capital spending in the Asset Condition category (excluding separately tracked large projects) was $20.3 million, which was $0.1 million under the FY 2022 budget of $20.3 million. The major drivers of this variance are as follows:

- Capital spending on URD projects was $5.6 million, over budget by $0.9 million. The majority of the overage related to a specific URD project that required special equipment for ledge removal and additional labor to complete.

- Capital spending on I&M was $1.3 million, $1.7 million under budget due to the streamlined program's focus on addressing priority and backlog work.

- Capital spending on the Franklin Square 11kV Substation project continued from FY 2021 and totaled $1.5 million during FY 2022. This project is associated with the Transmission project taking place at the Franklin Square Substation. The distribution project scope included a new outdoor 11 kV riser structure, removal of existing 11kV cable during coordinated outages and installation of new 11kV cable. Minimal budget for this project was included in the FY 2022 Plan because requirements were identified after the budget was set. The project is complete and was placed into service.

- Capital spending on the Franklin Square Breaker Replacement project was $0.7 million under budget as of March 31, 2022. Spending associated with the installation of the breakers was delayed due to the lack of vendor availability and will shift to FY 2023.

b. <u>Non-Infrastructure</u>

During FY 2022, capital spending in the Non-Infrastructure category was $1.1 million, which was $0.2 million under the FY 2022 budget of $1.3 million. The primary driver of the underspend relates to the resequencing of work required by a third party for the Copper to Fiber Conversion project.

c. <u>System Capacity and Performance</u>

During FY 2022, capital spending for the System Capacity and Performance category was $15.3 million, which was $5.1 million under the FY 2022 budget of $20.4 million. The major drivers of this variance are as follows:

- Capital spending on the Aquidneck Island projects was $3.9 million which was $2.5 million under budget. Drivers include FY 2022 work shifted into FY 2021, reduction of contingencies, and actuals coming in less than estimates.

- Capital spending on the New Lafayette Substation project was $2.3 million, $0.4 million over budget. Spending was in excess of budget due to the continued coordination of civil work with a DG project taking place at the same site.

- Capital spending on VVO projects was $2.6 million, $0.6 million under budget. The primary driver of the underspend relates to a distribution line project that has been shifted to FY 2023.

- Capital spending on 3V0 projects was $0.4 million, $1.1 million under budget due to the removal of projects from the FY 2022 Plan impacted by future retirements.

- Capital spending on EMS projects was $0.8 million, $0.5 million under budget. FY 2022 capital spending was reduced to align with the results of area studies.

- Capital spending on projects related to COVID load shifts was $0.9 million, $1.1 million under budget. Work on the 59F3 and 72F5 Lines, along with some smaller blanket level work, will be completed in FY 2023. Until the work is completed, the Company continues to monitor load and will take immediate action to manage the system safely and reliably.

d. Separately Tracked Large Projects

During FY 2022, capital spending on the Southeast Substation, Dyer Street Substation and Providence Area projects in the Asset Condition category was $15.5 million, $4.6 million under the budget of $20.2 million. Each project is discussed below and in Attachment G.

- Capital spending on the Southeast Substation project was $2.9 million, $0.8 million over the $2.1 million budget. The remaining portion of the Dunnell Park substation and the majority of the distribution line went into service during FY 2022. Work on the Pawtucket substation will continue into FY 2023.

- Capital spending on Dyer Street substation was $5.1 million, $4.6 million under the $9.7 million budget. The project was under budget due to delays in material deliveries. Work shifted into FY 2023 has been reflected in the proposed FY 2023 ISR Plan.

- Capital spending on the Providence Area Study projects (Admiral Street projects) was $7.5 million, $0.9 million under the budget of $8.4 million.

e. Large Project Variances

The Company provides explanations for large projects[2] with variances that exceed +/- 10% of the annual fiscal year budget in quarterly reports. These projects represented $29.8 million of the FY 2022 budget of $101.6 million. This project information is provided in Attachment E.

f. New Distribution System Technology Update

The Quarterly Updates include an explanation of all new technologies the Company is exploring to assist in distribution system planning, particularly as they relate to the integration of distributed energy resources or to providing additional visibility on the distribution grid. Most recently, the Company has increased its use of Python Scripting to improve automation in CYME as well as other computer programs. For example, the COVID-19 scenario analysis performed during FY 2021 utilized Python scrips to run the initial CYME analysis.

3. Investment Placed-in-Service

During the FY 2022, $89.3 million of plant additions were placed in service which was 91% of the FY 2022 target. Details by spending rationale are included in Attachment B.

4. Vegetation Management

During FY 2022, the Company completed 1,376 miles or 100% of its annual distribution mileage cycle pruning goal. O&M spending on vegetation management was $11.3 million. The Company has seen an increase in contractor and police detail costs in FY 2022, which resulted in an overspend of $460,000.

Attachment C provides the spending for FY 2022 and the Enhanced Hazard Tree Mitigation (EHTM) removal counts by circuit. The Company has completed removal of trees which were impacted by the Gypsy Moth infestation. No additional Gypsy Moth trees have been removed this fiscal year.

[2] Large projects are defined as exceeding $1.0 million in total project cost.

5. Inspection and Maintenance (I&M)

During the FY 2022, the Company completed 100% of its annual structure inspection goal within budget, with associated operating expense spending of $0.5 million. This spending includes mobile elevated voltage testing and repairs which the PUC approved in Docket No. 4237.

The Company began performing inspections on its overhead distribution system in FY 2011 and began performing the repairs based on those inspections in FY 2012. Deficiencies found are categorized as Level I, II, or III. Level I deficiencies are repaired immediately or within 30 days of the inspection. During FY 2022, five Level I deficiencies were identified and repaired within twelve days. The Company has completed repairs for 34 percent of the total deficiencies found. This information is summarized in the tables below.

Summary of Deficiencies and Repair Activities RI Distribution				
Year Inspection Performed	**Priority Level/Repair Expected**	**Deficiencies Found (Total)**	**Repaired as of 3/31/22**	**Not Repaired as of 3/31/22**
FY 2011	I	18	18	0
	II	13,146	13,128	18
	III	28	28	0
FY 2012	I	17	17	0
	II	15,847	15,544	303
	III	626	624	2
FY 2013	I	15	15	0
	II	25,883	16,496	9,387
	III	8,780	4,637	4,143
FY 2014	I	11	11	0
	II	22,096	4,380	17,716
	III	8,414	3,027	5,387
FY 2015	I	5	5	0
	II	20,805	2	20,803
	III	4,351	0	4,351
FY 2016	I	2	2	0
	II	11,018	1,236	9,782
	III	6,441	198	6,243
FY 2017	I	2	2	0
	II	8,567	7	8,560
	III	7,272	1	7,271
FY 2018	I	11	11	0
	II	8,639	12	8,627
	III	7,196	14	7,182
FY 2019	I	28	28	0
	II	3,699	0	3,699
	III	2,464	0	2,464
FY 2020	I	19	19	0
	II	186	28	158
	III	26	0	26
FY 2021	I	0	0	0
	II	53	0	53
	III	37	0	37
FY 2022	I	5	5	0
	II	149	1	148
	III	59	3	56
Total Since Program Inception	**I, II, III**	**175,915**	**59,499**	**116,416**

Manual Elevated Voltage Testing				
Manual Elevated Voltage Testing	**Total System Units Requiring Testing**	**FY 2022 Units Completed thru 03/31/22**	**Units with Voltage Found (>1.0v)**	**Percent of Units Tested with Voltage (>1.0v)**
Distribution Facilities	269,753	52,343	0	0%
Underground Facilities	12,438	2,600	0	0%
Street Lights	4,929	1,900	1	0%

During FY 2022, the Company's manual elevated voltage testing identified one instance of elevated voltage which was communicated and addressed by the respective town.

FY 2022 I&M program costs and other O&M spending are shown in Attachment D.

Attachment A

US Electricity Distribution - Rhode Island
Capital Spending by Spending Rationale
For the Fiscal Year Ending March 31, 2022
($000)

	FY 2022		
	Budget	**Actuals**	**Over Spend / (Under Spend)**
Customer Request/Public Requirement	$27,237	$34,340	$7,103
Damage Failure	$12,198	$20,200	$8,002
Total Non-Discretionary Spending	*$39,435*	*$54,540*	*$15,105*
Asset Condition	$20,330	$20,279	($51)
Non-Infrastructure	$1,310	$1,100	($210)
System Capacity & Performance	$20,373	$15,303	($5,071)
	$42,013	*$36,682*	*($5,331)*
Large Projects Separately Tracked	$20,153	$15,513	($4,640)
Total Discretionary Spending	*$62,165*	*$52,195*	($9,971)
Total Capital Spending	**$101,600**	**$106,735**	**$5,134**

Attachment B

US Electricity Distribution - Rhode Island
Plant Additions by Spending Rationale
For the Fiscal Year Ending March 31, 2022
($000)

	Target	Actuals	% of Target Placed In Service
Customer Request/Public Requirement	$25,830	$25,707	100%
Damage Failure	14,838	21,736	146%
Subtotal Non-Discretionary	*40,668*	*47,443*	*117%*
Asset Condition (w/Sep Tracked Large Projects)	39,097	29,570	76%
Non- Infrastructure	1,102	806	73%
System Capacity & Performance	17,620	11,522	65%
Subtotal Discretionary	*57,819*	*41,898*	*72%*
Total Plant Additions	**$98,487**	**$89,341**	91%

Attachment C

US Electricity Distribution - Rhode Island
Vegetation Management O&M Spending
For the Fiscal Year Ending March 31, 2022
($000)

	Budget	Actual	% Spend
Cycle Pruning (Base)	$6,600	$6,540	99%
Hazard Tree	1,500	1,543	103%
Sub-T (on & off road)	500	481	96%
Police/Flagman Details	775	873	113%
Pockets of Poor Performance	200	235	117%
Core Crew (all other activities)	1,225	1,591	130%
Total VM O&M Spending	**$10,800**	**$11,262**	**104%**

Enhanced Hazard Tree Mitigation Update

District	Circuit	Substation	Hazard Tree Removals
Coastal	49_56_16F1	Coventry	27
Coastal	49_56_85T1	Wood River	145
Capital	49_56_155F2	Chase Hill Substation	56
Coastal	49_56_155F4	Chase Hill Substation	54
Coastal	49_56_155F6	Chase Hill Substation	18
Capital	49_53_34F2	Chopmist	74
Capital	49_53_34F3	Chopmist	86
Capital	49_53_4F1	Barrington	24
Capital	49_53_4F2	Barrington	31
Capital	49_53_5F1	Warren	5
Coastal	49_56_52F3	Warwick	43
Totals			**563**

Attachment D

US Electricity Distribution - Rhode Island
Inspection and Maintenance Program and Other O&M Spending
For the Fiscal Year Ending March 31, 2022
($000)

	Budget	Actual	% Spend
Opex Related to Capex	$421	$149	35%
Inspections & Repair Related Costs	$475	$463	97%
System Planning & Protection Coordination Study	$25	$0	0%
VVO/CRV Program	$262	$208	79%
Total I&M Program and Other O&M Spending	$1,183	$819	

Attachment E

US Electricity Distribution - Rhode Island
Project Variance Report
For the Fiscal Year Ending March 31, 2022
($000)

	FY 2022			
Project Description	**FY 2022 Budget**	**FY 2022 Actuals**	**Over / (Under)**	**Variance Cause**
Aquidneck Island Projects	$6,434	$3,908	($2,527)	Jepson Sub - CAPEX pulled into FY21. Newport D Line Conv - Actuals coming in less than estimates.
New Lafayette Substation	$1,857	$2,284	$427	Carryover from FY 2021 of civil work costs to enable efficiencies by coordinating with a DG project taking place on the same site.
Dyer Street Indoor Sub	$9,717	$5,136	($4,581)	See Attachment G for additional details.
Providence Study - Phase 1A	$4,966	$4,485	($481)	See Attachment G for additional details.
Providence Study - Phase 1B	$2,895	$2,793	($102)	See Attachment G for additional details.
Franklin Sq Breaker Replacement	$1,804	$1,102	($702)	Due to vendor unavailability, FY22 breakers were not installed. Will be installed during Q1 of FY23.
Westerly Transformer #2 Failure	$0	$868	$868	Failed transformer, a spare transformer was installed and placed in service. 1st payment made on new spare transformer, remaining payments will be made in FY23.
Franklin Square Replacement of 11kV Equipment	$49	$1,538	$1,489	Requirements identified after FY22 budget was set therefore minimal budget was included in the FY 2022 Plan. Project completed and placed in service in Q3.
Southeast Substation	$2,082	$2,925	$843	See Attachment G for additional details.
	$29,805	**$25,038**	**($4,766)**	

Attachment F

US Electricity Distribution - Rhode Island
Damage/Failure Detail by Work Type
For the Fiscal Year Ending March 31, 2022
($000)

Operations Description	D-Line Blanket	Property Damage	D-Sub Blanket	Storms	Specifics	Grand Total
Engineering/Design/Supervision	$1,035	$63	$17	$643	$100	$1,858
OH Elec Distribution	3,714	(248)	0	6,208	107	9,782
OH Transformers/Capacitors/Regulators/Meters	708	10	0	430	0	1,147
Other	1,164	25	(185)	210	126	1,341
Outdoor Lighting	71	5	0	1	0	76
Substation	0	0	927	0	1,078	2,004
Switching and Restoration	136	52	26	31	9	255
Traffic Control	373	42	1	136	1	554
UG Elec Distribution	3,127	145	0	88	0	3,361
UG Transformers/Capacitors/Regulators/Meters	302	(1)	0	11	0	312
Total before reclassification	**10,631**	**93**	**786**	**7,759**	**1,421**	**20,690**
Reclassification adjustment between D/F and A/R	(490)					(490)
Total after reclassification	**$10,141**	**$93**	**$786**	**$7,759**	**$1,421**	**$20,200**

Attachment G

US Electricity Distribution - Rhode Island
Separately Tracked Large Projects
For the Fiscal Year Ending March 31, 2022

Southeast Substation
Predates existing Area Study Process
Current Status – Step 4.4 – Design and Execute

	FY22 Actuals & Current Forecast		FY22 ISR Budget	
	FY22 Actuals	Total Project Cost Forecast	FY22 Budget	Total Project Cost Forecast
Southeast Substation Project	**$2,925**	**$23,254**	**$2,082**	**$21,886**

During FY 2022, capital spending on the Southeast Substation project was $2.9 million, $0.8 million over the budget of $2.1 million. The Dunnell Park substation portion of this project is complete and went into service in March 2021. FY 2022 capital spending on the substation was site civil work that considered final grading, paving and fencing, and processing final payments to a civil contractor responsible for substation foundations. A significant portion of the distribution line project went into service during FY 2022. Capital spending was incurred on Dunnell Park for final civil work and the additional scope of work on Pawtucket for feeder reconfigurations, additions of reclosers on the distribution line system and circuit breaker upgrade on Pawtucket substation to maintain adequate and reliable service to the Pawtucket network. Pawtucket #1 construction has begun, and completion is scheduled for the second quarter of FY 2024.

In total, the Company currently expects capital spending to be $23.3 million for this project as compared with the estimate when sanctioned of $21.1 million. Additional spending was necessary due to field conditions requiring environmental management of an additional volume of soil, construction site congestion requiring additional resources such as crane and other equipment rentals, increased costs on final civil work at Dunnell Park substation, and the reconfiguration and equipment on the distribution network to avoid reliability issues noted above.

Dyer Street Substation

Predates existing Area Study Process
Current Status – Step 4.4 – Design and Execute

	FY22 Actuals & Current Forecast		FY22 ISR Budget	
	FY22 Actuals	Total Project Cost Forecast	FY22 Budget	Total Project Cost Forecast
Dyer Street Substation Project	$5,135	$16,947	$9,717	$14,628

During FY 2022, capital spending on the Dyer Street Substation project was $5.1 million, $4.6 million under the budget of $9.7 million. Necessary environmental permits have been obtained for the build at the South Street location for the Dyer Street project. Delayed delivery of the metal clad switchgear, delays in permits, and weather have resulted in shifting forecasted capital spend from the fourth quarter of FY 2022 to the first quarter of FY 2023. Construction is being phased to minimize impacts. The switchgear was delivered to the site in the first quarter of FY 2023.

In total, the Company currently expects capital spending to be $16.9 million as compared to the estimate of $16.7 million when sanctioned. The re-scoped Dyer Street Substation project at the South Street Substation location consists of building an external substation in the vicinity of the South Street Substation. The work will involve the installation of two new 11 kV to 4.16 kV transformers and the corresponding risers and switches, the installation of a metal clad switchgear, and the needed distribution feeder getaways. Benefits of building within the South Street substation vicinity are that the Company does not have to install numerous components including the ground grid, the substation fence, lighting, and trenching. The project is expected to go into service in the second quarter of FY 2023.

Providence Study – Admiral Street Substation - Phase 1A
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Step 4.4B – Construction

	FY22 Actuals & Current Forecast		FY22 ISR Budget	
	FY22 Actuals	Total Project Cost Forecast	FY22 Budget	Total Project Cost Forecast
Providence Study Projects - Phase 1A	**$4,485**	**$8,562**	**$4,966**	**$10,492**

During FY 2022, capital spending on Phase 1A of the Providence Study projects was $4.5 million, $0.5 million under the budget of $5.0 million. The decrease in capital spending was the result of reduced risk and a delay in some work which pushed labor and contractor charges into FY 2023. In total, the Company currently expects capital spending of $8.6 million for this project as compared to the $10.4 million budget presented in the FY 2022 ISR Plan and the estimate of $10.0 million when sanctioned. The work is currently on schedule to be completed in the second quarter FY 2023.

Providence Study – Admiral Street Substation - Phase 1B
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Step 4.4A – Final Engineering

	FY22 Actuals & Current Forecast		FY22 ISR Budget	
	FY22 Actuals	Total Project Cost Forecast	FY22 Budget	Total Project Cost Forecast
Providence Study Projects - Phase 1B	**$2,793**	**$46,264**	**$2,895**	**$24,443**

During FY 2022, capital spending on Phase 1B of the Providence Study projects was $2.8 million, $0.1 million under the budget of $2.9 million. Substation and distribution line final engineering and design including ground penetrating radar along with new duct bank route, permitting, distribution line material procurement, and substation long lead equipment procurement were conducted. No construction was scheduled in FY 2022.

In total, the Company expects capital spending of $46.2 million for this project as compared to the $24.4 million budget presented in the FY 2022 ISR Plan. Estimates have changed as the projects have progressed through the project development phase. The earlier estimate of this project was based on higher level engineering information. Changes between the original estimate and the current estimate were highlighted in the FY 2022 ISR First Quarter report. During the second quarter additional spending of was added to the forecast related to a required upgrade of the existing small main line conductor to standard mainline conductor on the Olneyville distribution line.

Providence Study – Admiral Street Substation - Phases 2-4
Providence Area Study Implementation Plan 2016 – 2030 (May 2017)
Current Status – Step 4.3 - Develop & Sanction

	FY22 Actuals & Current Forecast		FY22 ISR Budget	
	FY22 Actuals	Total Project Cost Forecast	FY22 Budget	Total Project Cost Forecast
Providence Study Projects - Phases 2 and 4	**$175**	**$45,513**	**$495**	**$33,945**

During FY 2022, capital spending on Phases 2-4 of the Providence Study projects was $0.2 million, $0.3 million under the budget of $0.5 million. No construction took place in FY 2022.

In total, the Company currently expects capital spending of $45.5 million for this project as compared to the $33.9 million budget presented in the FY 2022 ISR Plan. Estimates for the Knightsville substation and distribution line projects have been revised as the projects progress through the project development phase. The earlier estimates were based on higher level engineering information. Primary drivers with associated increased costs are as follows:

- Duct bank and earthwork increases - $0.5m
- Resourcing, labor, and team costs - $3.3m
- Contingency, risk, AFUDC, and A&G costs - $7.1m

Attachment H

US Electricity Distribution - Rhode Island
Meter Purchases
For the Fiscal Year Ending March 31, 2022

Quantity of Meters Purchased		
Type	**Description**	**Quantity**
METER	KV2C - 9S	192
METER	KV2C - 16S CL320	108
METER	KV2C - 16S CL200	36
METER	KV2C - 2S CL320	24
METER	KV2C - 2S CL200	36
SWITCHES	"B" SWITCHES	4
SWITCHES	"K" SWITCHES	3
METER	CENTRON - 2S ERT CL200	12,600
METER	CENTRON - 12S ERT CL200	3,360
METER	CENTRON - C1SR, CL320 240V	240
METER	CENTRON 3-ERT 16S CL320	120
METER	CENTRON 3-ERT 16S CL200	360
METER	2S AMR 240V CL200	3,360
INSTRUMENT TRANSFORMER	CUR OUTDOOR 120/1 14.4KV	18
INSTRUMENT TRANSFORMER	CUR OUTDOOR 175/1 34.5KV	6
INSTRUMENT TRANSFORMER	CUR OUTDOOR 50/5 15KV	29
INSTRUMENT TRANSFORMER	CUR OUTDOOR 75/5 15KV	3
INSTRUMENT TRANSFORMER	CUR OUTDOOR 100/5 15KV	27
INSTRUMENT TRANSFORMER	CUR OUTDOOR 200/5 15KV	9
INSTRUMENT TRANSFORMER	CUR OUTDOOR 300/5 15KV	12
INSTRUMENT TRANSFORMER	CUR OUTDOOR 800/5 600V	36
INSTRUMENT TRANSFORMER	CUR OUTDOOR 60/1 7.2KV	30
INSTRUMENT TRANSFORMER	400:5 BASE BUSHINGS	120
INSTRUMENT TRANSFORMER	600:5 BASE BUSHINGS	360
INSTRUMENT TRANSFORMER	200:5 CAP	120
INSTRUMENT TRANSFORMER	400:5 CAP	288
INSTRUMENT TRANSFORMER	1500:5 CAP	60
	TOTAL	**21,561**

Attachment 2

2021 Electric Service Quality Report

nationalgrid

Andrew S. Marcaccio
Senior Counsel

April 29, 2022

VIA ELECTRONIC MAIL

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

RE: Docket 3628 – 2021 Service Quality Report (Electric Operations)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid (National Grid or the Company), enclosed, please find an electronic version[1] of the Company's Annual Service Quality Report which assesses the quality of the Company's electric operations for the performance period of January 1, 2021 through December 31, 2021 (the 2021 Service Quality Report or Report). As indicated in the Report, the Company performance for both reliability and customer service was within acceptable levels and, as a result, the Company did not incur a penalty.

The 2021 Service Quality Report stems from the Company's electric Service Quality Plan (the SQ Plan) as approved by the Public Utilities Commission (the PUC or Commission) through Order Nos. 18294, 19020, and 22456.[2] The purpose of the SQ Plan is to ensure that customers receive a reasonable level of service. To this end, the SQ Plan establishes performance standards for service reliability, which includes the categories of interruption frequency and interruption duration, and for customer service, which includes the categories of customer contact and telephone calls answered. For each category, a benchmark or range representing acceptable performance is set forth. If the Company's performance falls below the acceptable range in any of the four categories, a penalty is assessed. The Company cannot earn a monetary award for exceeding expectations; however, it can accrue offsets for good performance in one category which may be used to offset a penalty incurred in the other categories. For additional details on the SQ Plan, please see Attachment 1 of the Settlement Agreement.[3]

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[1] Per a communication from Commission counsel on October 4, 2021, the Company is submitting an electronic version of this filing followed by six (6) hard copies filed with the Clerk within 24 hours of the electronic filing.

[2] Through Order No. 18294, the PUC approved a Settlement Agreement between the Company and the Division of Public Utilities and Carriers (Division) which incorporated the SQ Plan to be effective January 1, 2005 (the Settlement Agreement). The SQ Plan also includes amendments made in 2007 (Order No. 19020) and 2016 (Order No. 22456).

[3] See http://www.ripuc.ri.gov/eventsactions/docket/3628-NEC-Ord18294(7-12-05).pdf

280 Melrose Street, Providence, RI 02907
T: 401-784-4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

For 2021, the Company did not incur a penalty. Specifically, the Company's performance fell within an acceptable range for each of the four categories, meaning there were no penalties assessed. Although not needed, the Company did not accrue any offsets for exemplary performance. For a summary of the results, please see Section 2 of the Report.

In addition, the Report: (1) References quarterly reports filed by the Company that detail the worst performing circuits; (2) References monthly reports filed by the Company that detail trouble/non-outages; (3) Calculates the Company's annual meter reading performance; and (4) Identifies Major Event Days. In accordance with the SQ Plan, Major Event Days are not factored into the Company's performance under this Report and are separately analyzed and reported. For additional details on these items, please see Section 3 of the Report.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 3628 Service List
Christy Hetherington, Esq.
John Bell, Division

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

___________________________________ April 29, 2022
Joanne M. Scanlon Date

National Grid – Electric Service Quality Plan – Compliance - Docket 3628
Service List Updated 4/29/2022

Name	E-mail Distribution List	Phone
Jennifer Brooks Hutchinson Andrew Marcaccio National Grid 280 Melrose Street Providence, RI 02907-1438	jennifer.hutchinson@nationalgrid.com;	401-784-7288
	Celia.obrien@nationalgrid.com;	
	Andrew.marcaccio@nationalgrid.com;	
	Joanne.scanlon@nationalgrid.com;	
Leticia C. Pimentel, Esq. Steven J. Boyajian, Esq. Robinson & Cole LLP One Financial Plaza, 14th Floor Providence, RI 02903	lpimentel@rc.com;	401-709-3337
	Sboyajian@rc.com;	
Leo Wold, Esq. Division of Public Utilities & Carriers 89 Jefferson Boulevard Warwick, RI 02888 Tiffany Parenteau, Esq. Dept. of Attorney General Office	Leo.wold@dpuc.ri.gov;	
	John.bell@dpuc.ri.gov;	
	Robert.Bailey@dpuc.ri.gov;	
	Joseph.Shilling@dpuc.ri.gov;	
	Al.contente@dpuc.ri.gov;	
	Michelle.Barbosa@dpuc.ri.gov;	
	Machaela.Seaton@dpuc.ri.gov;	
	Al.contente@dpuc.ri.gov;	
	Paul.roberti@dpuc.ri.gov;	
	Margaret.L.Hogan@.ri.gov;	
	gschultz@riag.ri.gov;	
	Egolde@riag.ri.gov;	

Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440
Original & 9 copies file w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Boulevard Warwick, RI 02888	Luly.massaro@puc.ri.gov; Todd.bianco@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov;	401-780-2107
PPL Electric Utilities Ronald Reybitz Stephen Breininger	rjreybitz@pplweb.com; skbreininger@pplweb.com;	

The Narragansett Electric Company
d/b/a National Grid

2021 Service Quality Report

April 29, 2022

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 3628

Submitted by:

nationalgrid

TABLE OF CONTENTS

SECTION 1
RELIABILITY AND CUSTOMER SERVICE PERFORMANCE STANDARDS

Interruption Frequency and Duration

Under the Service Quality Plan, an interruption is defined as the loss of electric service to more than one customer for more than one minute. The interruption duration is defined as the period of time, measured in minutes, from the initial notification of the interruption event to the time when service has been restored to the customers. Interruptions are tracked using System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). SAIFI is calculated by dividing the total number of customers interrupted by the total number of customers served. SAIFI measures the number of times per year the average customer experienced an interruption. This is an average, so in any given year some customers will experience no interruptions, and some will experience several interruptions. SAIDI measures the length of interruption time that the average customer experienced for the year. It is calculated by dividing the total customer minutes of interruption by the total number of customers served.

Certain events are defined as Major Event Days and are excluded from the calculation of reliability performance standards for penalty and offset assessment. There were four Major Event Days that occurred during 2021. The Major Event Days are March 2, August 22, October 27, and November 13. On May 10, 2021, the Company received support from the Division of Public Utilities and Carriers ("Division") to treat March 1-2, 2021 storm as Major Event Days under the Electric Service Quality Plan. On July 8, 2021, the Company filed a Petition with the Public Utilities Commission ("PUC") seeking advance approval and confirmation from the PUC that March 1-2, 2021 could be treated as Major Event Days under the Electric Service Quality Plan. On January 12, 2022, the PUC found that "the Commission does not need to rule on this request and that National Grid should follow the stated terms of the Service Quality Plan when it files its Annual Report on May 1, 2022." The Company is filing this Annual Report excluding March 2, 2021 only. However, the Company believes that it would be appropriate and consistent with the intent of the Electric Service Quality Plan and the Division's prior handling of similar events to exclude March 1, 2021. Under either calculation, the Company would not be in a penalty position for 2021.

2021 Total Frequency Standard		**2021 Frequency (SAIFI) Results**	
Frequency of Interruptions per Customer	(Penalty)/Offset	Frequency of Interruptions per Customer	Annual (Penalty)/Offset
Greater than 1.18	($916,000)		
1.06-1.18	linear interpolation		
0.84-1.05	$0	0.949	$0
0.75-0.83	linear interpolation		
Less than 0.75	$229,000		

2021 Duration (SAIDI) Standard		**2021 Duration (SAIDI) Results**	
Duration of Interruptions (minutes)	(Penalty)/Offset	Duration of Interruptions (minutes)	Annual (Penalty)/Offset
Greater than 89.9	($916,000)		
72.0-89.9	linear interpolation		
45.9-71.9	$0	68.8	$0
36.7-45.8	linear interpolation		
Less than 36.7	$229,000		

CUSTOMER SERVICE PERFORMANCE STANDARDS

Customer Contact Survey

The customer contact survey results are based on responses from National Grid's Rhode Island Electric customers from a survey performed by an independent third-party consultant, Praxis Research Partners. Praxis surveys a random sample of customers who have contacted National Grid recently to determine their level of satisfaction with their most recent contact with the Company regarding any call reason. Survey results are based on a composite measure of two questions from National Grid's internal contactor survey: (1) Overall, on a scale from 1 to 10, where 1 means "dissatisfied", and 10 means "satisfied", how satisfied are you with the services provided by National Grid? (2) Overall, on a scale from 1 to 10, where 1 means "dissatisfied", and 10 means "satisfied", how satisfied are you with the quality of service provided by the telephone representative? The individual score for each question is the percentage of respondents who provided a rating of "8", "9", or "10" on a 10-point scale, where 1 means "dissatisfied", and 10 means "satisfied". The "percent satisfied" composite score is a simple arithmetic average of the satisfaction score from each question.

2021 Customer Contact Standard		**2021 Customer Contact Results**	
Percent Satisfied	(Penalty)/Offset	Percent Satisfied	Annual (Penalty)/Offset
Less than 74.4%	($184,000)		
74.4%-78.7%	linear interpolation		
78.8%-87.6%	$0	85.5%	$0
87.7%-92.0%	linear interpolation		
More than 92.0%	$46,000		

Telephone Calls Answered Within 20 Seconds

The calls answered performance standard reflects the annual percentage of calls answered within 20 seconds. "Calls answered" include calls answered by a customer service representative (CSR) and calls completed within the Voice Response Unit (VRU). The time to answer is measured once the customer selects to either speak with a CSR or use the VRU.

2021 Calls Answered Standard		**2021 Calls Answered Results**	
% Answered Within 20 Seconds	(Penalty)/Offset	% Answered Within 20 Seconds	Annual (Penalty)/Offset
Less than 53.5%	($184,000)		
53.5% - 65.7%	linear interpolation		
65.8% - 90.4%	$0	81.82%	$0
90.5% - 100.0%	linear interpolation, to maximum of $46,000		

SECTION 2: CALCULATION OF PENALTY/OFFSET

National Grid
2021 Results of Service Quality Plan
Calculation of Penalty/Offset

Performance Standard	Potential Penalty (a)	Potential Offset (b)	2021 Results (c)	Maximum Penalty (d)	One Std Dev. Worse Than Mean (e)	Mean (f)	One Std Dev. Better Than Mean (g)	Maximum Offset (h)	Annual (Penalty)/ Offset (i)
Reliability - Frequency	$ 916,000	$ 229,000	0.95	1.18	1.05	0.94	0.84	0.75	$0
Reliability - Duration	$ 916,000	$ 229,000	68.8	89.9	71.9	57.5	45.9	36.7	$0
Customer Service - Customer Contact Survey	$ 184,000	$ 46,000	85.5%	74.4%	78.8%	83.2%	87.6%	92.0%	$0
Customer Service - Telephone Calls Answered	$ 184,000	$ 46,000	81.8%	53.5%	65.8%	78.1%	90.4%	100.0%	$0
Total Penalty/Offset	$ 2,200,000	$ 550,000							$0

Notes:

Columns (a), (b), and (d)-(h) are per the Amended Electric Service Quality Plan, RIPUC Docket No. 3628.

Column (c) represents the actual 2021 annual results for the performance standards listed in the first column.

Column (i) is calculated as follows:

- For Reliability Standards:
  - If Column (c) is between Column (g) and Column (e): $0
  - If Column (c) is between Column (h) and Column (g): [Column (g) - Column (c)] ÷ [Column (g) - Column (h)] x Column (b)
  - If Column (c) is between Column (e) and Column (d): [Column (c) - Column (e)] ÷ [Column (d) - Column (e)] x Column (a)
  - If Column (c) is greater than Column (d): 100% of Column (a)
  - If Column (c) is less than Column (h): 100% of Column (b)
- For Customer Service Standards:
  - If Column (c) is between Column (e) and Column (g): $0
  - If Column (c) is between Column (g) and Column (h): [Column (c) - Column (g)] ÷ [Column (e) - Column (d)] x Column (b)
  - If Column (c) is between Column (d) and Column (e): [Column (e) - Column (c)] ÷ [Column (e) - Column (d)] x Column (a)
  - If Column (c) is less than Column (d): 100% of Column (a)
  - If Column (c) is greater than Column (h): 100% of Column (b)

SECTION 3
ADDITIONAL REPORTING CRITERIA

Under the Company's Service Quality Plan, the following additional reporting criteria are required to be filed with the PUC.

1. **Reporting Requirement:** Each quarter, the Company will file a report of 5% of all circuits designated as worst performing on the basis of customer frequency. Included in the report will be:
   1. The circuit ID and location.
   2. The number of customers served.
   3. The towns served.
   4. The number of events.
   5. The average duration.
   6. The total customer minutes.
   7. A discussion of the cause or causes of events.
   8. A discussion of the action plan for improvements including timing.

   Results: The Company filed its first quarter 2021 feeder ranking results on July 30, 2021, the second quarter results on February 17, 2022, the third quarter results on March 16, 2022, and fourth quarter results on March 29, 2022.

2. **Reporting Requirement:** The Company will track and report monthly the number of calls it receives in the category of Trouble, Non-Outage. This includes inquiries about dim lights, low voltage, half-power, flickering lights, reduced TV picture size, high voltage, frequently burned-out bulbs, motor running problems, damaged appliances and equipment, computer operation problems, and other non-interruptions related inquiries.

   Results: The Company filed the required Trouble, Non-Outage reports during 2021, with the final report for the 13 months ended December 2021 filed on January 21, 2022.

3. **Reporting Requirement:** The Company will report its annual meter reading performance as an average of monthly percentage of meters read.

Results: During 2021, the Company's annual meter reading performance (as an average of monthly percentage of meters read) was 98.6%, compared to 98.19% during 2020, and 99.15% during 2019. The following table details the percentage of meters read per month for 2021, 2020, and 2019.

Monthly Percentage of Meters Read

	2021	2020	2019
January	98.59%	99.01%	99.21%
February	98.53%	99.07%	99.23%
March	98.63%	98.72%	99.26%
April	98.70%	97.85%	99.29%
May	98.70%	97.88%	99.32%
June	98.75%	97.67%	99.29%
July	98.66%	97.92%	99.24%
August	98.36%	97.05%	99.22%
September	98.83%	98.27%	99.12%
October	98.57%	98.32%	98.70%
November	98.18%	98.38%	99.03%
December	98.69%	98.17%	98.94%
YTD Average	98.60%	98.19%	99.15%

4. **<u>Reporting Requirement</u>:** For each event defined as a Major Event Day, the Company will prepare a report, which will be filed annually as part of the annual Service Quality filing, detailing the following information:

    1. Start date/Time of event
    2. Number/Location of crews on duty (both internal and external crews)
    3. Number of crews assigned to restoration efforts
    4. The first instance of mutual aid coordination
    5. First contact with material suppliers
    6. Inventory levels: pre-event/daily/post-event
    7. Date/Time of request for external crews
    8. Date/Time of external crew assignment
    9. # of customers out of service by hour
    10. Impacted area
    11. Cause
    12. Weather impact on restoration
    13. Analysis of protective device operation
    14. Summary of customers impacted

<u>Results</u>: IEEE Std. 1366-2012[1] identifies reliability performance during both day-to-day operations and Major Event Days. Major Event Days represent those few days during the year on which the energy delivery system experienced stresses beyond that normally expected, such as severe weather. A day is considered a Major Event Day if the daily SAIDI exceeds a threshold value, calculated using the IEEE methodology. For 2021 the T_{MED} value was 6.67 minutes of SAIDI (using IEEE Std. 1366-2012 methodology). There were four days during four separate storms that exceeded this threshold in 2021. These storms occurred on March 2, August 22, October 27, and November 13. The storms are described below.

[1] RIPUC Order No 19020 refers to IEEE Std. 1366-2003. This standard has been superseded by IEEE Std. 1366-2012. The updated standard requires no changes for identifying Major Event Days or calculating thresholds.

March 2, 2021 Storm

1. **Start date/Time of event:**

   The storm began at 2:00 p.m. on March 1 with scattered interruptions starting at approximately at 12:00 a.m., March 2. The storm peaked around 1:51 a.m., March 2. The peak reached 9,563 customers interrupted.

2. **Number/Location of crews on duty (both internal and external crews):**

   The Company secured 255 internal and external field crews to restore power to customers, consisting of approximately 89 external crews and 166 internal crews. The field crews included transmission and distribution overhead line, forestry, substation, and underground personnel.

3. **Number of crews assigned to restoration efforts:**

   At peak, the Company had the following crews performing restoration activities throughout the impacted areas in the State.

   Crew Type
   Internal Overhead Line - 137 crews
   External Overhead Line - 41 crews
   Internal Wire Down - 112 crews
   Internal Transmission - 2 crews
   Internal Underground - 25 crews
   Internal Substation - 78 crews
   Contractor Forestry - 147 crews
   Damage Appraiser - 10 crews

4. **The first instance of mutual aid coordination:**

   The first call for mutual aid coordination started at 8:30 a.m. on March 2.

5. **First contact with material suppliers:**

   The first contact with material suppliers was on March 2.

6. **Inventory levels: pre-event/daily/post-event:**

PLANT#	1107	1108	1115	1120	1101 Alloc.	
LOCATION	LINCOLN	PROVIDENCE	NORTH KINGST	MIDDLETOWN	RI Allocated Inventory Balance @ NEDC	Total RI LOCATION Inventory Balances
3/2/2021	$ 9,985	$ 583,926	$ -	$ 230,034	$ 6,997,483	$ 7,821,428

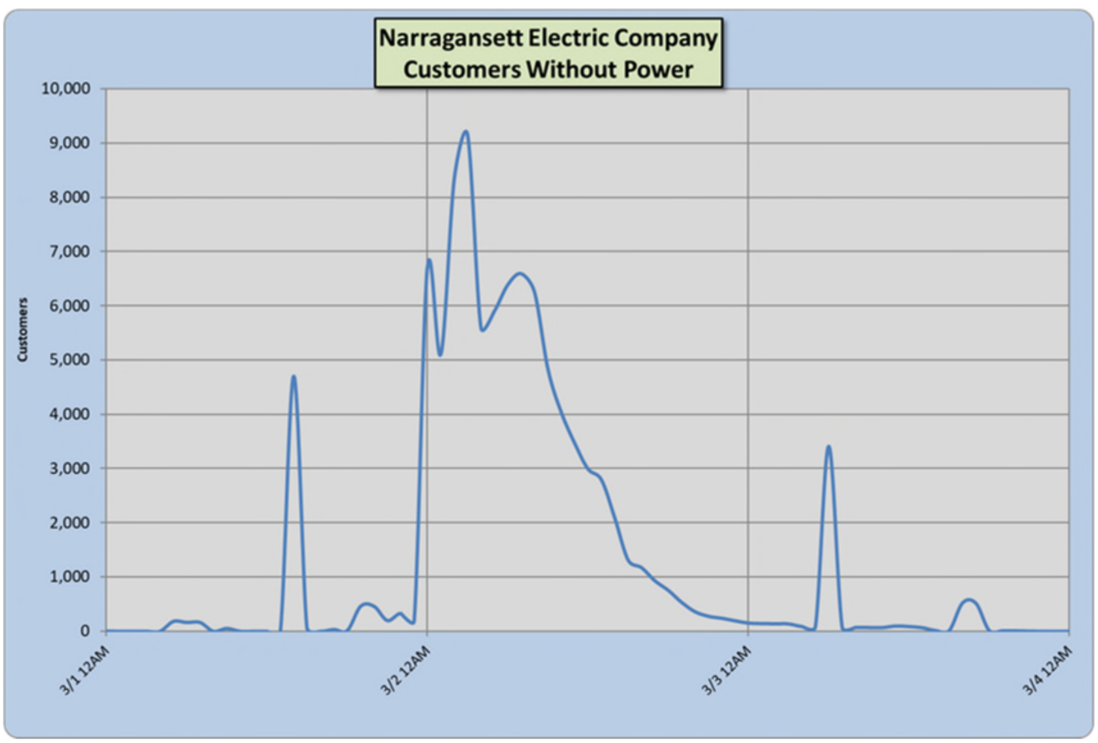
7. **Date/Time of request for external crews:**

Given the potential magnitude of the Storm and a forecast of hazardous winds, the Company secured crews in advance from its contractors of choice and other outside contractors to support restoration efforts for all New England as part of its regional preparation for the Storm, consistent with its Emergency Response Plan.

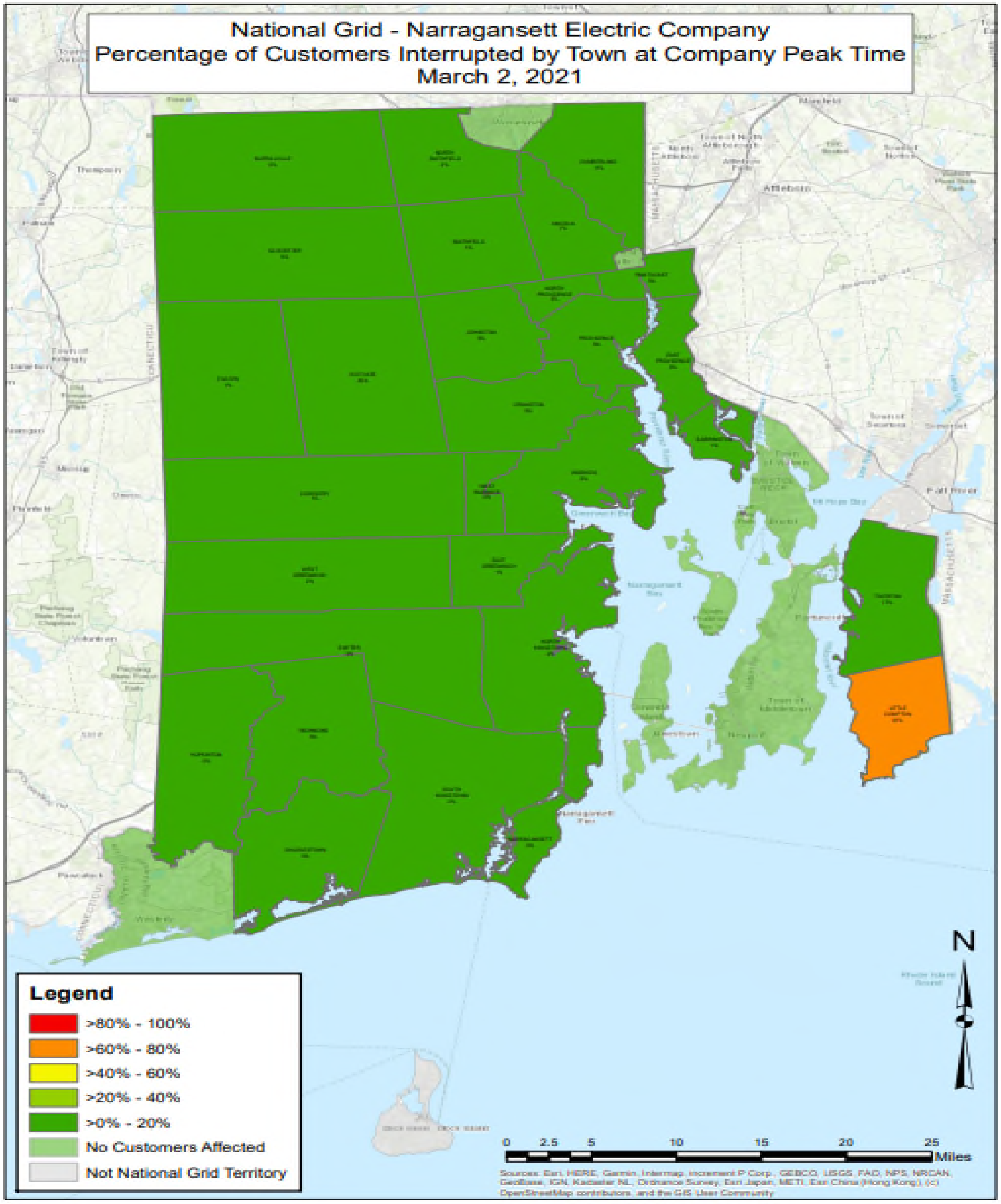
8. **Date/Time of external crew assignment:**

External crews were assigned to work the night shift on March 1.

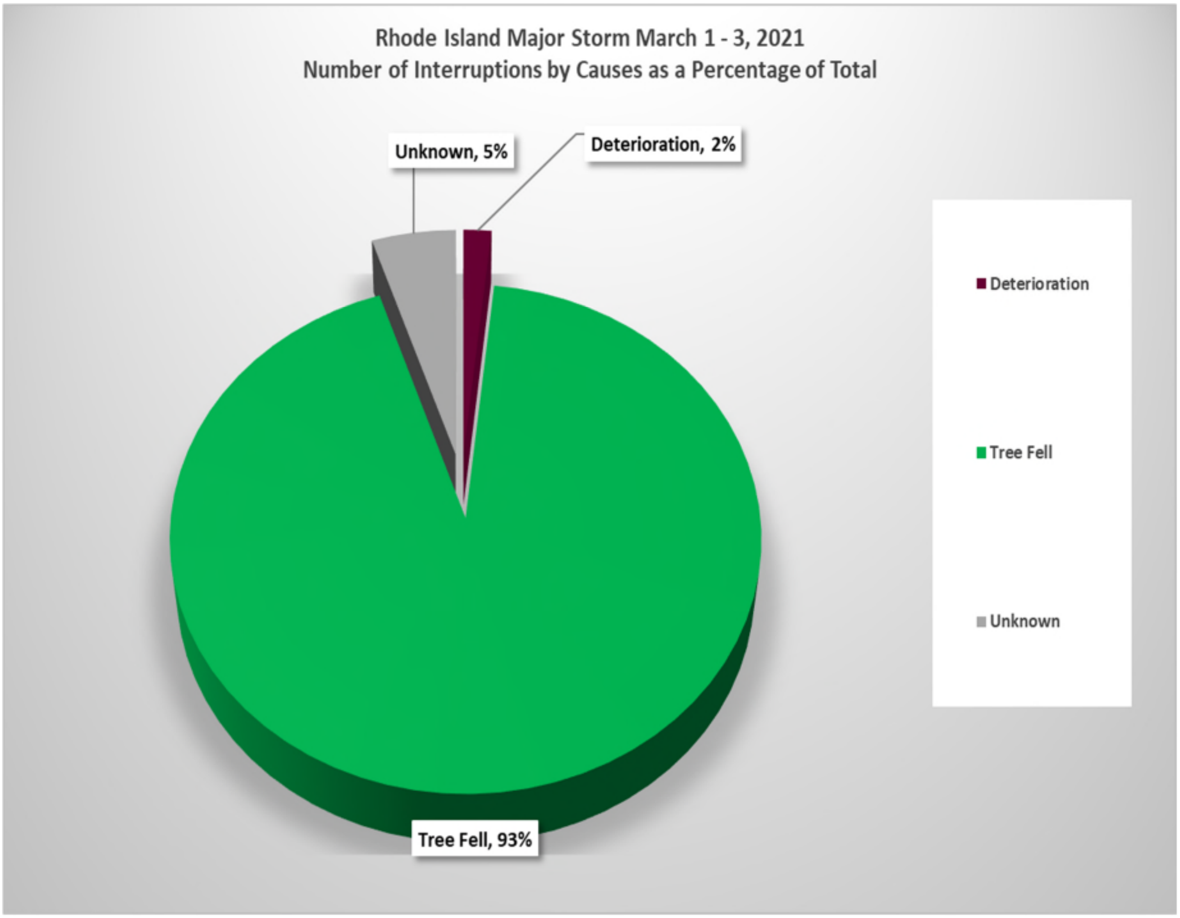
9. **# of customers out of service by hour:**



10. Impacted area:



11. Cause:


Rhode Island Major Storm March 1 - 3, 2021
Number of Interruptions by Causes as a Percentage of Total
Unknown, 5%
Deterioration, 2%
Tree Fell, 93%
Deterioration
Tree Fell
Unknown

12. Weather impact on restoration:

The March 1-2, 2021 Storm was a strong weather event that resulted in significant damage to the Company's electrical system. The Storm brought a cold front with hazardous wind gusts to portions of the Company's service territory. These strong wind gusts continued from late Monday morning through much of the day on Tuesday, March 2. Peak wind gusts were generally in the 45–50 mph range, with both Newport and North Kingstown experiencing a peak gust of 53 mph. The Town of Little Compton was affected most heavily with approximately 62 percent of its customers impacted by the event.

13. Analysis of protective device operation:

National Grid maintains a wide array of protection and interrupting devices designed to separate faulted components from the electrical system while containing outages to the smallest area practicable. On the distribution system, those devices include fuse cutouts, reclosers, and circuit breakers of various designs. On the transmission system, interrupting devices include circuit breakers, air-break switches, and circuit switchers. Protection relays are used to detect the faults and operate the interrupting device(s) to isolate a faulted component(s).

For the distribution system, design standards exist that indicate how protection devices are to be deployed and coordinated with other devices. Distribution engineers evaluate such devices under normal and fault conditions. Where recent performance may indicate a need for improvement, National Grid performs engineering studies and makes improvements. During a major storm like this event, outages in the distribution system may be far too extensive to assess the function and coordination of individual protection devices in detail, as the focus of storm response is on service restoration. A meaningful analysis would be difficult to perform unless there were specific indications of protection equipment mis-operation.

Protection standards, guides and practices also exist and are followed in the design of the National Grid's transmission system. Post-event analysis of all interruptions in the National Grid Bulk Electric System (BES) is performed to confirm proper operation of protection systems. If an improper operation is identified, further analysis is conducted to identify the cause and to propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of mis-operation.

14. Summary of customers impacted:

March 1, 2021

On March 1, Rhode Island experienced 42 interruptions that affected 18,136 customers and 1,510,836 customer minutes of interruption. On average these interruptions resulted in 0.0363 SAIFI, 3.025 minutes of SAIDI. Since a SAIDI value of 3.025 minutes does not exceed the threshold value of 6.67 minutes, March 1 is not qualified as a Major Event Day under the IEEE methodology. As noted in Section 1, on May 10, 2021, the Company received support from the Division of Public Utilities and Carriers ("Division") to treat March 1-2, 2021 storm as Major Event Days under the Electric Service Quality Plan. On July 8, 2021, the Company filed a Petition with the Public Utilities Commission ("PUC") seeking advance approval and confirmation from the PUC that March 1-2, 2021 could be treated as Major Event Days under the Electric Service Quality Plan. On January 12, 2022, the PUC found that "the Commission does not need to rule on this request and that National Grid should follow the stated terms of the Service Quality Plan when it files its Annual Report on May 1, 2022." The Company is filing this Annual Report excluding March 2, 2021 only. However, the Company believes that it would be appropriate and consistent with the intent of the Electric Service Quality Plan and the Division's prior handling of similar events to exclude March 1, 2021. Under either calculation, the Company would not be in a penalty position for 2021.

March 2, 2021

On March 2, Rhode Island experienced 185 interruptions that affected 16,459 customers and 4,217,391 customer minutes of interruption. On average these interruptions resulted in 0.0330 SAIFI, 8.45 minutes of SAIDI. Since a SAIDI value of 8.45 minutes exceeds the threshold value of 6.67 minutes, March 2 is qualified as a Major Event Day under the IEEE methodology.

March 3, 2021

On March 3, Rhode Island experienced a total of 16 interruptions that affected 4,162 customers and 74,303 customer minutes of interruption. On average these interruptions resulted in 0.008 SAIFI and 0.15 minutes of SAIDI. Since a SAIDI value of 0.15 minutes is less than the threshold value of 6.67 minutes, March 3 does not qualify as a Major Event Day under the IEEE methodology.

August 22, 2021 Storm Henri

1. **Start date/Time of event:**

   The storm began in the early morning on Sunday, August 22 with scattered interruptions starting at approximately 6:00 a.m. and peaked around 2:00 p.m. on August 22. The peak reached 76,867 customers interrupted.

2. **Number/Location of crews on duty (both internal and external crews):**

   The Company secured a total of 1,022 internal and external field crews to restore power to customers, consisting of approximately 696 external crews and 326 internal crews. The field crews included transmission and distribution overhead line, forestry, substation, underground, wires down, and damage assessment personnel.

3. **Number of crews assigned to restoration efforts:**

   At peak, the Company had the following crews performing restoration activities throughout impacted areas of the State.

   Crew Type

   Internal Overhead Line - 206 crews

   External Overhead Line - 1,108 crews

   Internal Wire Down - 557 crews

   Internal Transmission - 6 crews

   Internal Underground - 33 crews

   Internal Substation - 114 crews

   Contractor Forestry - 601 crews

   Internal Damage Appraiser - 75 crews

4. **The first instance of mutual aid coordination:**

   The first call for mutual aid coordination started at 6:00 p.m. on August 20.

5. **First contact with material suppliers:**

   The first contact with material suppliers was on August 22.

6. **Inventory levels: pre-event/daily/post-event:**

PLANT#	1107	1108	1115	1120	1101 Alloc.	
LOCATION	LINCOLN	PROVIDENCE	NORTH KINGST	MIDDLETOWN	RI Allocated Inventory Balance @ NEDC	Total RI LOCATION Inventory Balances
8/22/2021	$ 9,985	$ 420,346	$ -	$ 230,034	$ 7,984,546	$ **8,644,911**

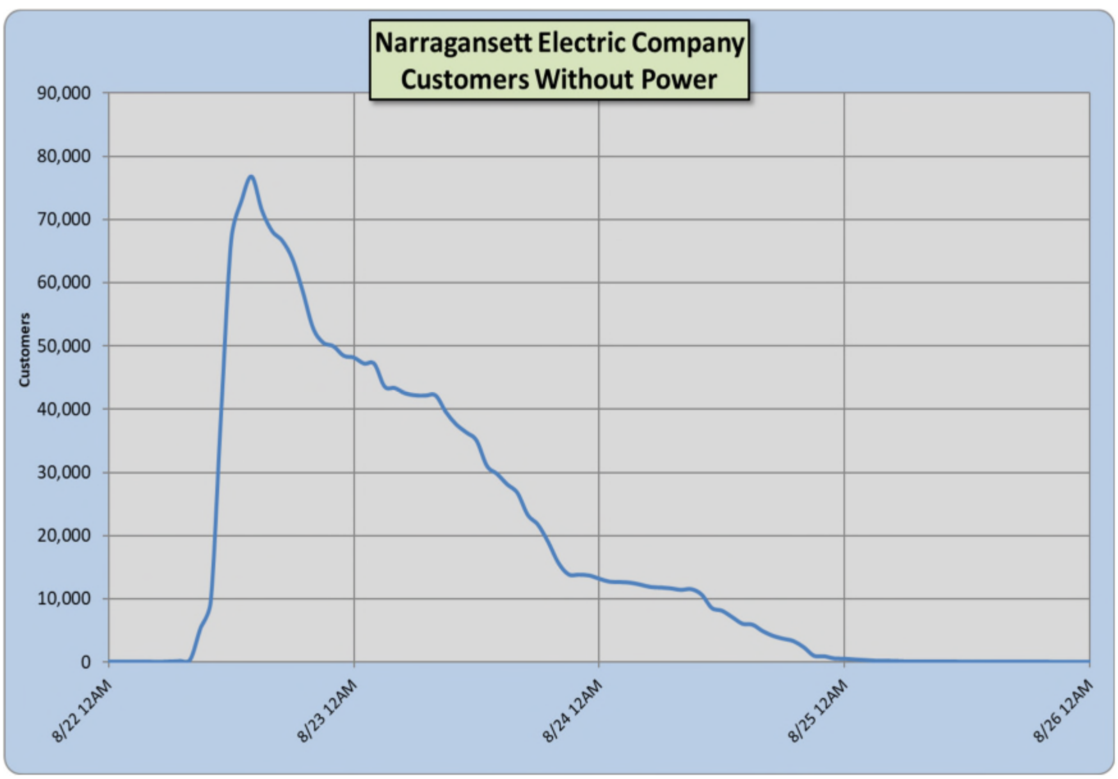
7. **Date/Time of request for external crews:**

Given the potential magnitude of the Storm and forecast of hazardous winds, the Company secured crews in advance from its contractors of choice and other outside contractors to support restoration efforts for all New England as part of its regional preparation for the Storm, consistent with its Emergency Response Plan.

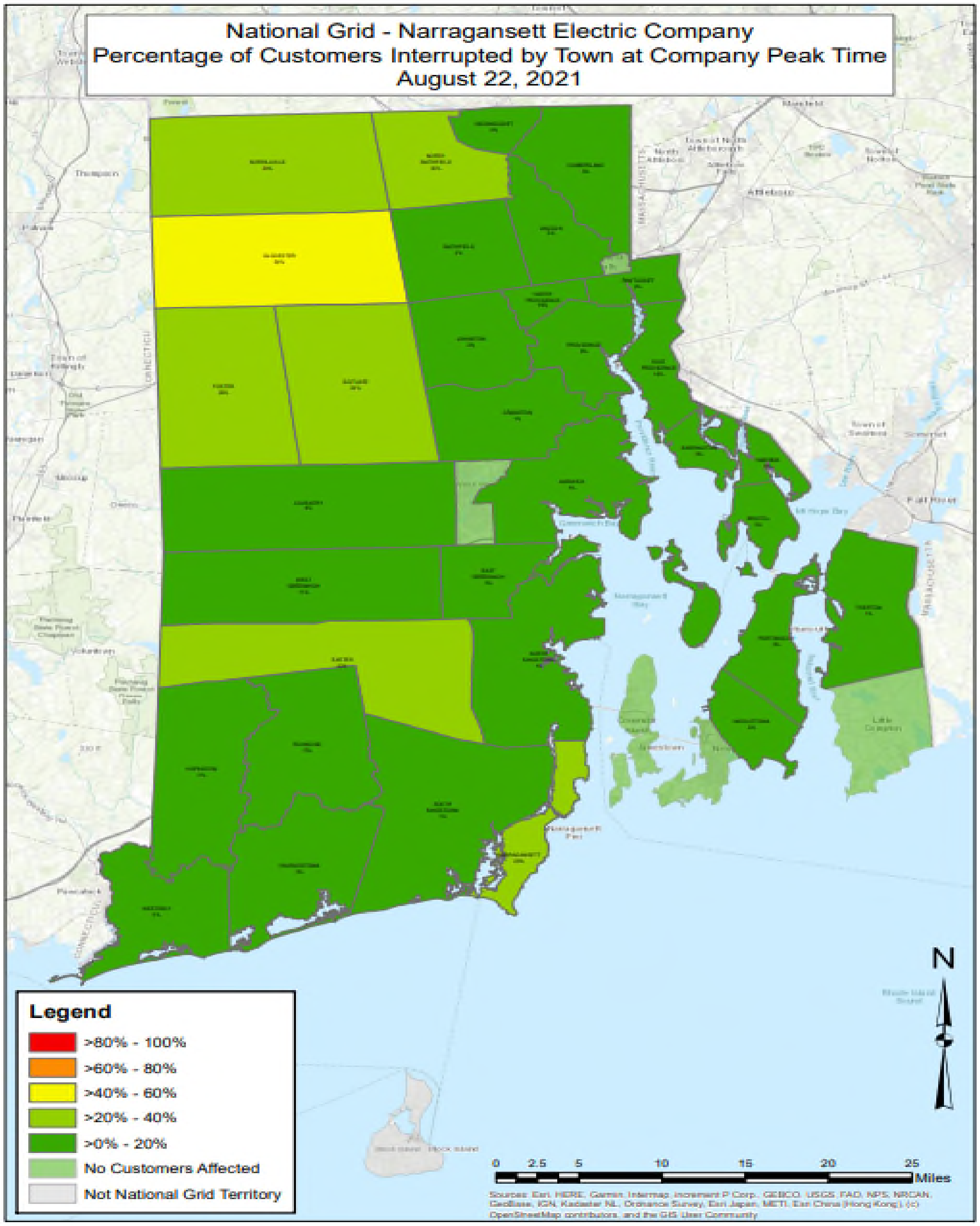
8. **Date/Time of external crew assignment:**

External crew were assigned to duty starting August 22.

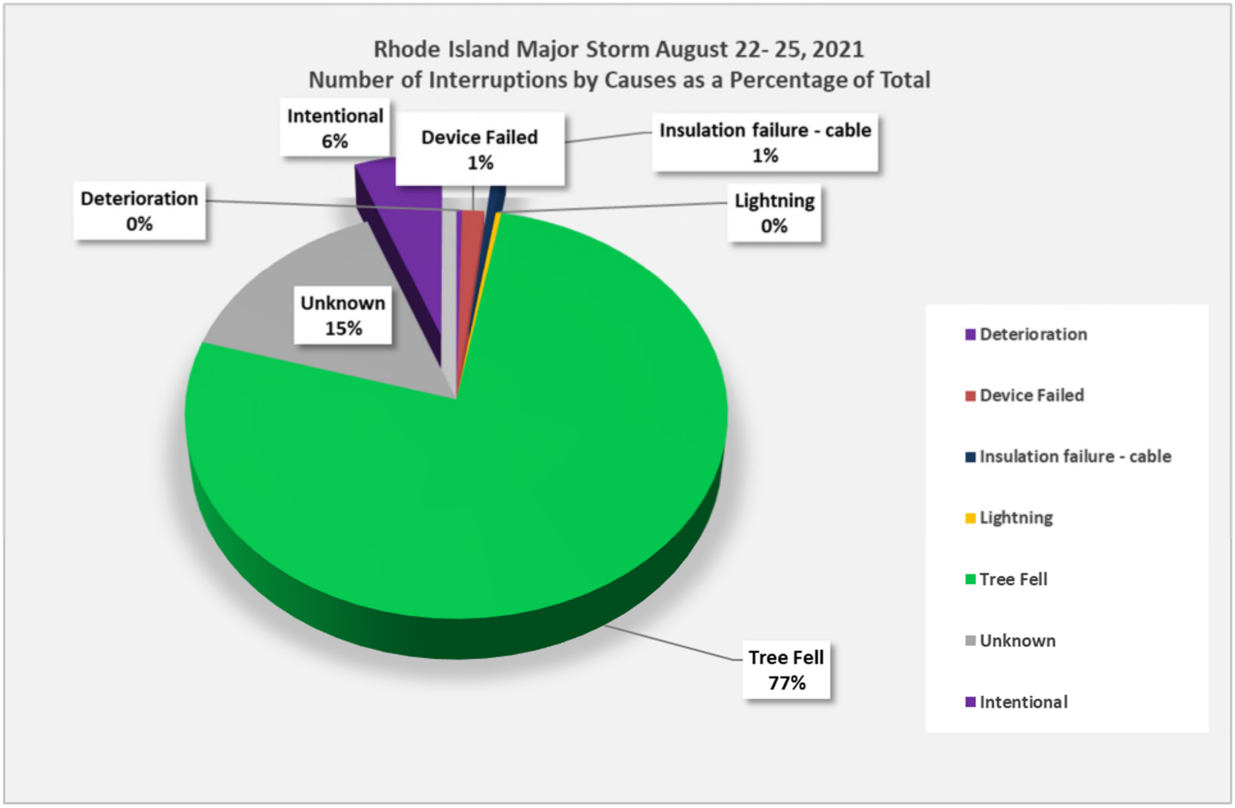
9. **# of customers out of service by hour:**



10. Impacted area:



11. Cause:


Rhode Island Major Storm August 22- 25, 2021
Number of Interruptions by Causes as a Percentage of Total
Intentional 6%
Device Failed 1%
Insulation failure - cable 1%
Deterioration 0%
Lightning 0%
Unknown 15%
Tree Fell 77%
Deterioration
Device Failed
Insulation failure - cable
Lightning
Tree Fell
Unknown
Intentional

12. Weather impact on restoration:

The Storm was a major weather event that resulted in significant damage to the Company's electrical system. The Storm brought heavy rain and strong wind gusts to the Company's service territory. Peak wind gusts were generally in the 50-60 mph range, with Point Judith experiencing a peak gust of 70 mph. The Towns of South Kingstown and Coventry were affected most heavily with approximately 76 and 56 percent of customers impacted by the event, respectively.

13. Analysis of protective device operation:

National Grid maintains a wide array of protection and interrupting devices designed to separate faulted components from the electrical system while containing outages to the smallest area practicable. On the distribution system, those devices include fuse cutouts, reclosers, and circuit breakers of various designs. On the transmission system, interrupting devices include circuit breakers, air-break switches, and circuit switchers. Protection relays are used to detect the faults and operate the interrupting device(s) to isolate a faulted component(s).

For the distribution system, design standards exist that indicate how protection devices are to be deployed and coordinated with other devices. Distribution engineers evaluate such devices under normal and fault conditions. Where recent performance may indicate a need for improvement, National Grid performs engineering studies and makes improvements. During a major storm like this event, outages in the distribution system may be far too extensive to assess the function and coordination of individual protection devices in detail, as the focus of storm response is on service restoration. A meaningful analysis would be difficult to perform unless there were specific indications of protection equipment mis-operation.

Protection standards, guides and practices also exist and are followed in the design of the National Grid's transmission system. Post-event analysis of all interruptions in the National Grid Bulk Electric System (BES) is performed to confirm proper operation of protection systems. If an improper operation is identified, further analysis is conducted to identify the cause and to propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of mis-operation.

14. Summary of customers impacted:

August 22, 2021

On August 22, Rhode Island experienced 428 interruptions that affected 94,730 customers and 105,389,853 customer minutes of interruption. On average these interruptions resulted in 0.19 SAIFI and 211.77 minutes of SAIDI. Since a SAIDI value of 211.77 minutes exceeded the threshold value of 6.67 minutes, August 22 qualified as a Major Event Day under the IEEE methodology.

August 23, 2021

On August 23, Rhode Island experienced 86 interruptions that affected 4,315 customers and 775,585 customer minutes of interruption. On average these interruptions resulted in 0.0087 SAIFI and 1.56 minutes of SAIDI. Since a SAIDI value of 1.56 minutes is less than the threshold value of 6.67 minutes, August 23 did not qualify as a Major Event Day under the IEEE methodology. The restoration continued on August 23.

August 24, 2021

On August 24, Rhode Island experienced 80 interruptions that affected 1,858 customers and 180,958 customer minutes of interruption. On average these interruptions resulted in 0.0037 SAIFI and 0.36 minutes of SAIDI. Since a SAIDI value of 0.36 minutes is less than the threshold value of 6.67 minutes, August 24 did not qualify as a Major Event Day under the IEEE methodology. The restoration continued on August 24.

August 25, 2021

On August 25, Rhode Island experienced 30 interruptions that affected 175 customers and 26,515 customer minutes of interruption. On average these interruptions resulted in 0.0004 SAIFI and 0.053 minutes of SAIDI. Since a SAIDI value of 0.053 minutes is less than the threshold value of 6.67 minutes, August 25 did not qualify as a Major Event Day under the IEEE methodology. The restoration continued on August 25.

October 27, 2021 Storm

1. **Start date/Time of event:**

   The storm began at 10:00 p.m. on October 26 with scattered interruptions starting at approximately 1:00 a.m. and peaked around 8:44 a.m. on October 27. The peak reached 83,524 customers interrupted.

2. **Number/Location of crews on duty (both internal and external crews):**

   The Company secured 532 internal and external field crews to restore power to customers, consisting of approximately 316 external crews and 216 internal crews. The field crews included transmission and distribution overhead line, forestry, substation, underground, wires down and damage assessment personnel.

3. **Number of crews assigned to restoration efforts:**

   At peak, the Company had the following crews performing restoration activities throughout the impacted areas in the State.

   Crew Type
   Internal Overhead Line - 305 crews
   External Overhead Line - 748 crews
   Internal Wire Down - 300 crews
   Internal Transmission - 5 crews
   Internal Underground - 60 crews
   Internal Substation - 178 crews
   Contractor Forestry - 453 crews
   Internal Damage Appraiser - 170 crews

4. **The first instance of mutual aid coordination:**

   The first call for mutual aid coordination was at 10:30 a.m. on October 26.

5. **First contact with material suppliers:**

   The first contact with material suppliers was on October 27.

6. **Inventory levels: pre-event/daily/post-event:**

PLANT#	1107	1108	1115	1120	1101 Alloc.	
LOCATION	LINCOLN	PROVIDENCE	NORTH KINGST	MIDDLETOWN	RI Allocated Inventory Balance @ NEDC	Total RI LOCATION Inventory Balances
10/27/2021	$ 9,985	$ 375,179	$ -	$ 221,263	$ 7,890,922	$ 8,497,349

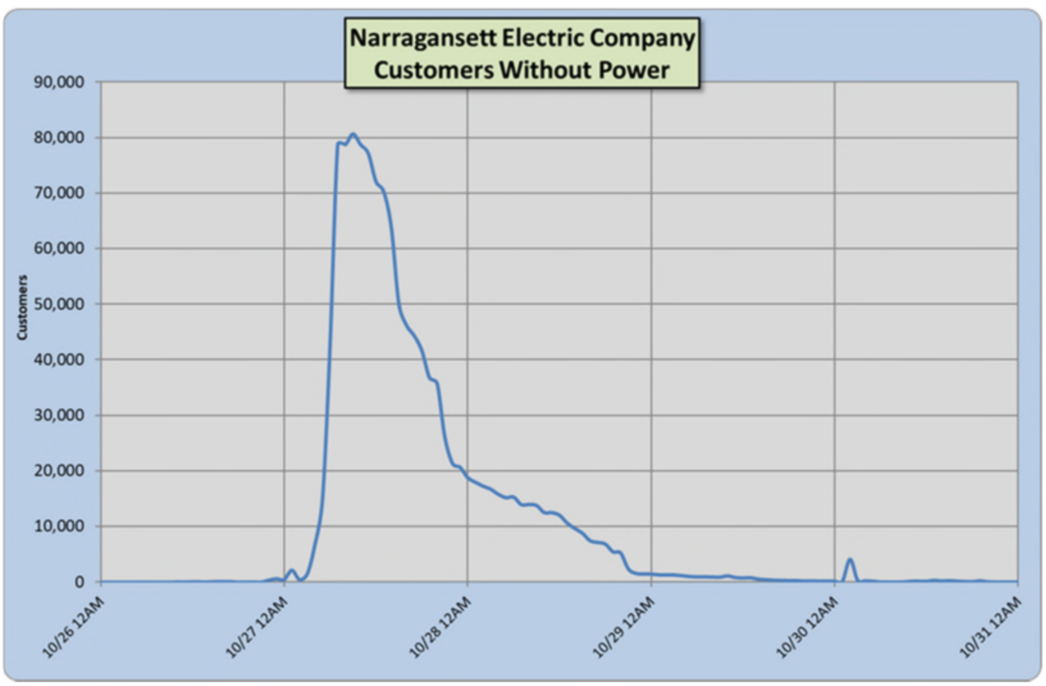
7. **Date/Time of request for external crews:**

The Company requested mutual assistance from companies in the North Atlantic Mutual Assistance Group ("NAMAG") to support restoration for this event. The first North Atlantic Mutual Assistance Group call was at 10:30 a.m. on October 26.

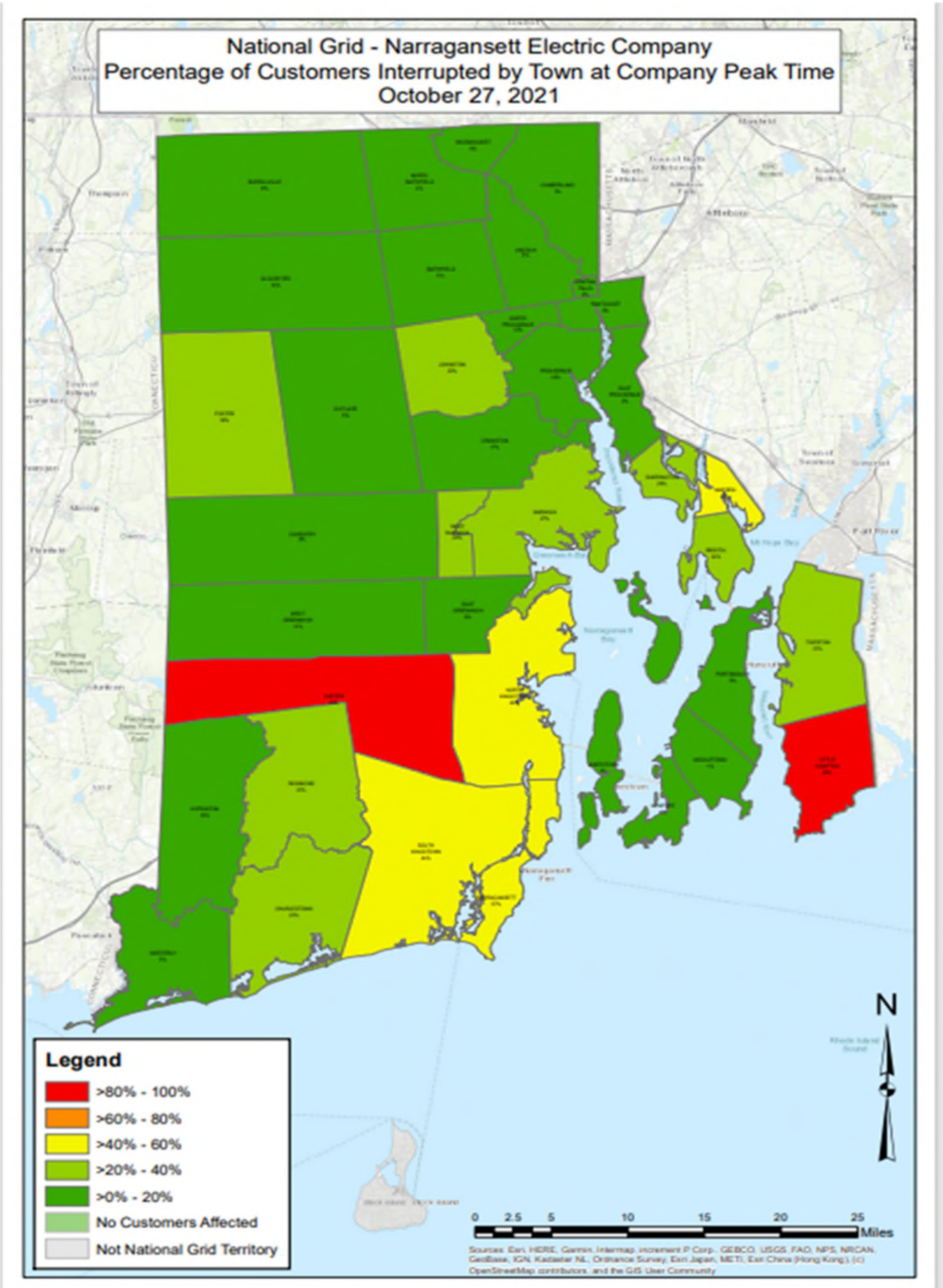
8. **Date/Time of external crew assignment:**

Mutual Assistance was assigned to duty starting October 26.

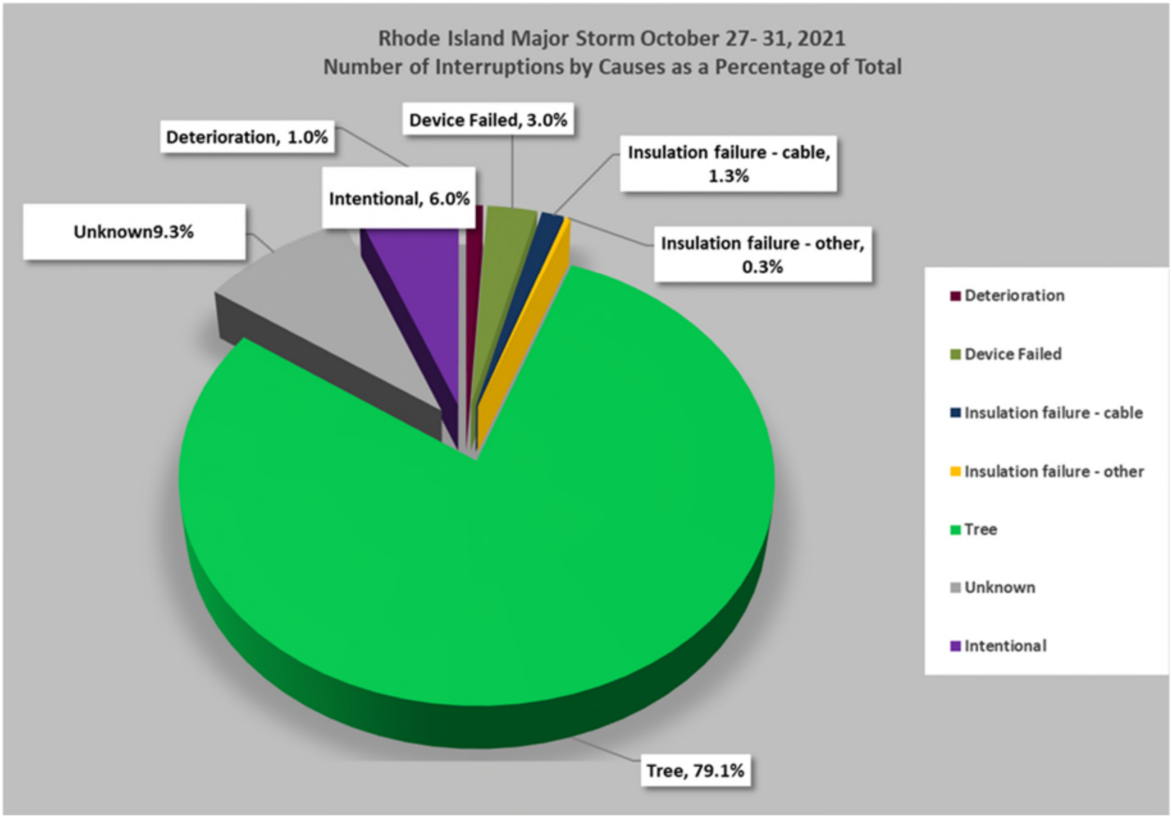
9. **# of customers out of service by hour:**



10. Impacted area:



11. Cause:


Rhode Island Major Storm October 27- 31, 2021
Number of Interruptions by Causes as a Percentage of Total
Deterioration, 1.0%
Device Failed, 3.0%
Insulation failure - cable, 1.3%
Intentional, 6.0%
Unknown9.3%
Insulation failure - other, 0.3%
Tree, 79.1%
Deterioration
Device Failed
Insulation failure - cable
Insulation failure - other
Tree
Unknown
Intentional

12. Weather impact on restoration:

The Storm was a major weather event that resulted in significant damage to the Company’s electrical system. The Storm brought heavy rain and strong wind gusts to the Company’s service territory. Peak wind gusts were generally in the 50-60 mph range, with Block Island experiencing a peak gust of 73 mph. The Towns of Little Compton and Narragansett were affected most heavily with approximately 100% percent of customers impacted by the event.

13. Analysis of protective device operation:

National Grid maintains a wide array of protection and interrupting devices designed to separate faulted components from the electrical system while containing outages to the smallest area practicable. On the distribution system, those devices include fuse cutouts, reclosers, and circuit breakers of various designs. On the transmission system, interrupting devices include circuit breakers, air-break switches, and circuit switchers. Protection relays are used to detect the faults and operate the interrupting device(s) to isolate a faulted component(s).

For the distribution system, design standards exist that indicate how protection devices are to be deployed and coordinated with other devices. Distribution engineers evaluate such devices under normal and fault conditions. Where recent performance may indicate a need for improvement, National Grid performs engineering studies and makes improvements. During a major storm like this event, outages in the distribution system may be far too extensive to assess the function and coordination of individual protection devices in detail, as the focus of storm response is on service restoration. A meaningful analysis would be difficult to perform unless there were specific indications of protection equipment mis-operation.

Protection standards, guides and practices also exist and are followed in the design of the National Grid’s transmission system. Post-event analysis of all interruptions in the National Grid Bulk Electric System (BES) is performed to confirm proper operation of protection systems. If an improper operation is identified, further analysis is conducted to identify the cause and to propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of mis-operation.

14. Summary of customers impacted:

October 26, 2021

On October 26, Rhode Island experienced 44 interruptions that affected 1,260 customers and 246,650 customer minutes of interruption. On average these interruptions resulted in 0.0025 SAIFI and 0.49 minutes of SAIDI. Since a SAIDI value of 0.49 minutes is less than the threshold value of 6.67 minutes, October 26 did not qualify as a Major Event Day under the IEEE methodology.

October 27, 2021

On October 27, Rhode Island experienced 528 interruptions that affected 113,718 customers and 75,911,178 customer minutes of interruption. On average these interruptions resulted in 0.227 SAIFI and 151.78 minutes of SAIDI. Since a SAIDI value of 151.78 minutes exceeds the threshold value of 6.67 minutes, October 27 qualified as a Major Event Day under the IEEE methodology.

October 28-30, 2021

On October 28, Rhode Island experienced 81 interruptions that affected 1,501 customers and 516,742 customer minutes of interruption. On average these interruptions resulted in 0.003 SAIFI and 1.03 minutes of SAIDI. Since a SAIDI value of 1.03 minutes is less than the threshold value of 6.67 minutes, October 28 did not qualify as a Major Event Day under the IEEE methodology. The restoration continued on October 29 and October 30, although neither day qualified as a Major Event Day.

November 13, 2021 Storm

1. **Start date/Time of event:**

   The storm began early morning on Saturday, November 13 with scattered interruptions starting at approximately 10:00 a.m. and peaked around 5:48 p.m. The peak reached 11,268 customers interrupted.

2. **Number/Location of crews on duty (both internal and external crews):**

   The Company secured 287 internal and external field crews to restore power to customers, consisting of approximately 71 external crews and 216 internal crews. The field crews included transmission and distribution overhead line, forestry, substation, underground, wires down.

3. **Number of crews assigned to restoration efforts:**

   At peak, the Company had the following crews performing restoration activities throughout the impacted areas in the State.

   Crew Type

   Internal Overhead Line - 183 crews

   External Overhead Line - 119 crews

   Internal Wire Down - 150 crews

   Internal Transmission - 3 crews

   Internal Underground - 33 crews

   Internal Substation - 100 crews

   Contractor Forestry - 90 crews

4. **The first instance of mutual aid coordination:**

   No mutual aid was called for this storm.

5. **First contact with material suppliers:**

   The first contact with material suppliers started on November 13.

6. **Inventory levels: pre-event/daily/post-event:**

PLANT#	1107	1108	1115	1120	1101 Alloc.	
LOCATION	LINCOLN	PROVIDENCE	NORTH KINGST	MIDDLETOWN	RI Allocated Inventory Balance @ NEDC	Total RI LOCATION Inventory Balances
11/13/2021	$ 9,985	$ 639,792	$ -	$ 221,263	$ 8,169,082	$ 9,040,122

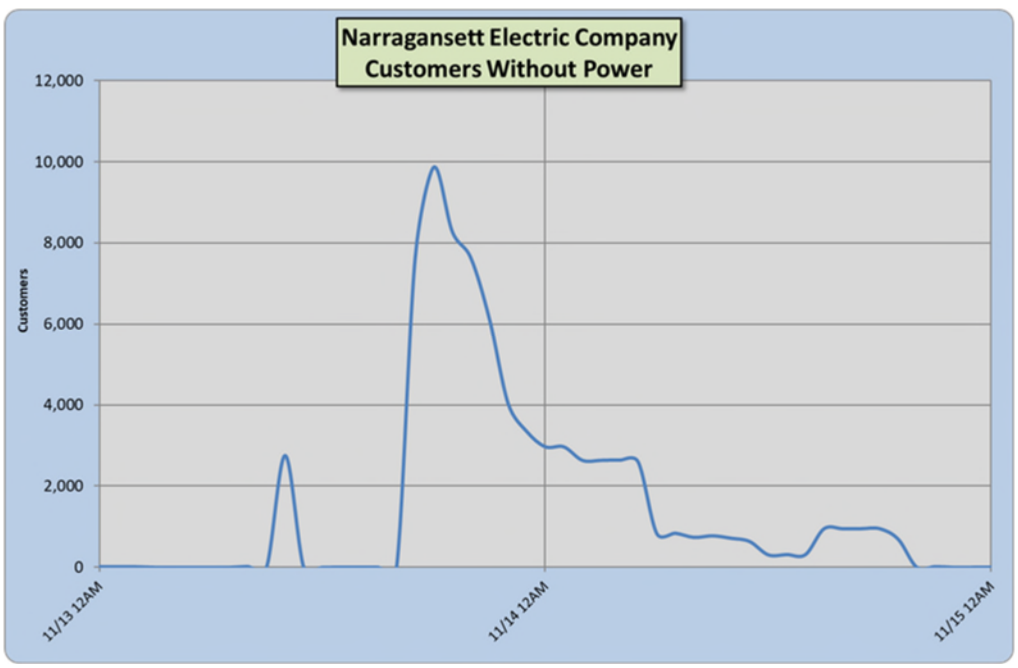
7. **Date/Time of request for external crews:**

The Company did not request mutual assistance from companies in the North Atlantic Mutual Assistance Group (“NAMAG”) to support restoration for this event. The Company requested external crews on November 10.

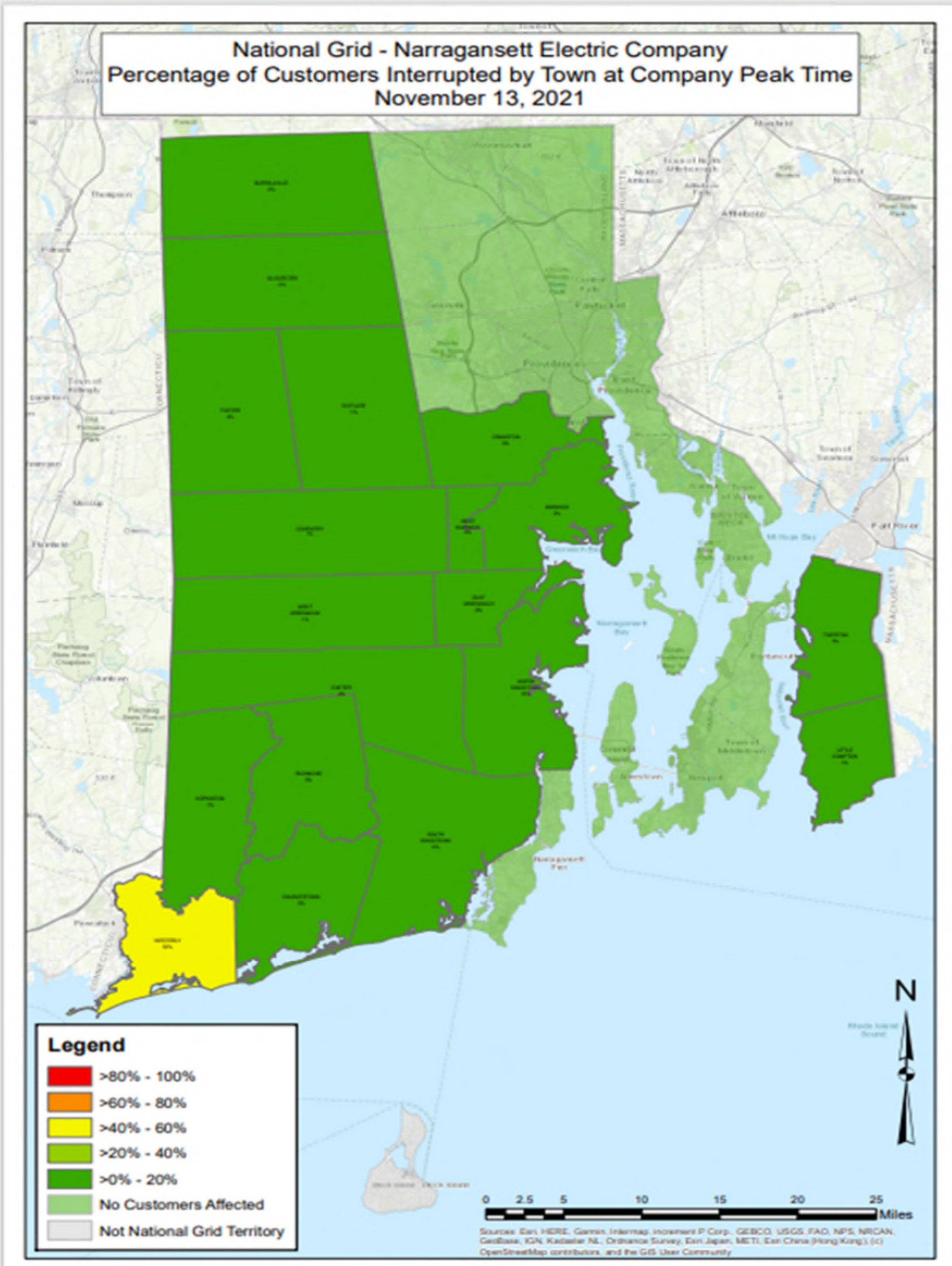
8. **Date/Time of external crew assignment:**

External crews were assigned to work starting November 12.

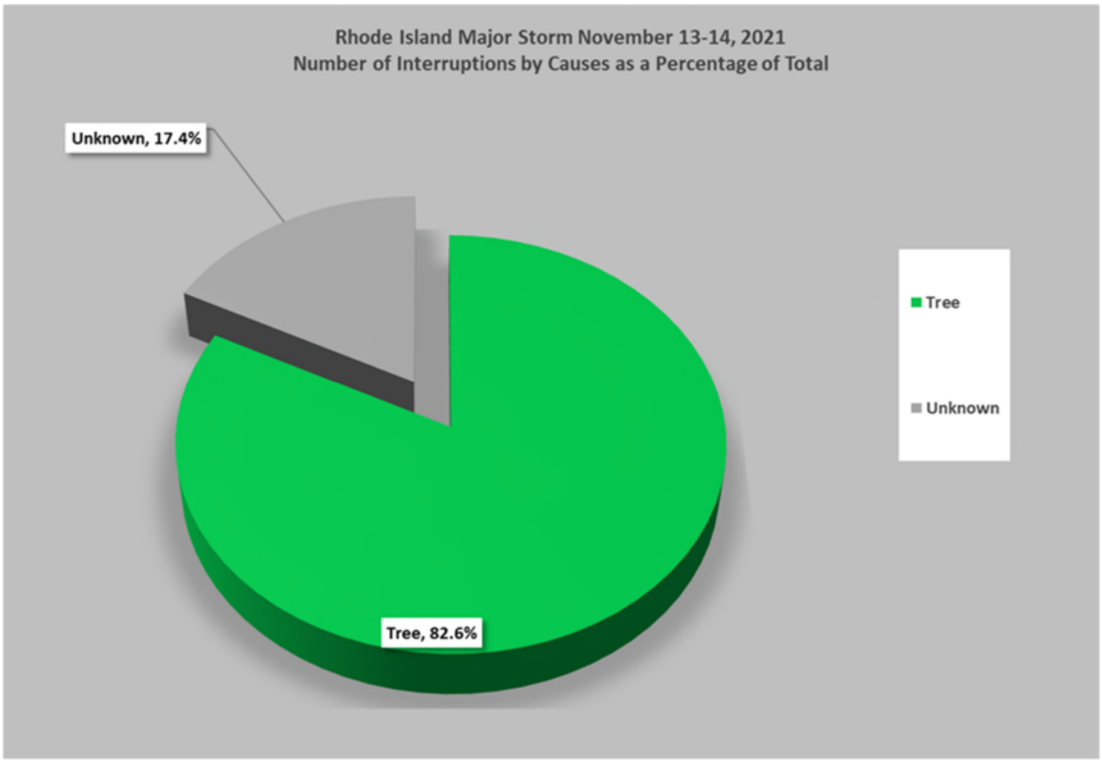
9. **# of customers out of service by hour:**



10. Impacted area:



11. Cause:


Rhode Island Major Storm November 13-14, 2021
Number of Interruptions by Causes as a Percentage of Total
Unknown, 17.4%
Tree, 82.6%
Tree
Unknown

12. Weather impact on restoration:

The Storm was a moderate weather event that resulted in significant damage to the Company's electrical system. The Storm brought rain and strong wind gusts to the Company's service territory. The Storm also brought three tornadoes that touched down in Rhode Island (first recorded tornadoes in November in Rhode Island since at least 1950, according to NWS Boston, which services Rhode Island) demonstrating the uniqueness and intensity of the front. Peak wind gusts were generally in the 45-50 mph range, with Conimicut Point experiencing a peak gust of 59 mph. The Town of Westerly was affected most heavily with approximately 72 percent of customers impacted.

13. Analysis of protective device operation:

National Grid maintains a wide array of protection and interrupting devices designed to separate faulted components from the electrical system while containing outages to the smallest area practicable. On the distribution system, those devices include fuse cutouts, reclosers, and circuit breakers of various designs. On the transmission system, interrupting devices include circuit breakers, air-break switches, and circuit switchers. Protection relays are used to detect the faults and operate the interrupting device(s) to isolate a faulted component(s).

For the distribution system, design standards exist that indicate how protection devices are to be deployed and coordinated with other devices. Distribution engineers evaluate such devices under normal and fault conditions. Where recent performance may indicate a need for improvement, National Grid performs engineering studies and makes improvements. During a major storm like this event, outages in the distribution system may be far too extensive to assess the function and coordination of individual protection devices in detail, as the focus of storm response is on service restoration. A meaningful analysis would be difficult to perform unless there were specific indications of protection equipment mis-operation.

Protection standards, guides and practices also exist and are followed in the design of the National Grid's transmission system. Post-event analysis of all interruptions in the National Grid Bulk Electric System (BES) is performed to confirm proper operation of protection systems. If an improper operation is identified, further analysis is conducted to identify the cause and to propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of mis-operation.

14. Summary of customers impacted:

November 13, 2021

On November 13, Rhode Island experienced 67 interruptions that affected 15,312 customers and 4,207,206 customer minutes of interruption. On average these interruptions resulted in 0.030 SAIFI and 8.4 minutes of SAIDI. Since a SAIDI value of 8.4 minutes exceeds the threshold value of 6.67 minutes, November 13 qualified as a Major Event Day under the IEEE methodology.

November 14, 2021

On November 14, Rhode Island experienced 20 interruptions that affected 193 customers and 30,664 customer minutes of interruption. On average these interruptions resulted in 0.0004 SAIFI and 0.15 minutes of SAIDI. Since a SAIDI value of 0.15 minutes is less than the threshold value of 6.67 minutes, November 14 does not qualify as a Major Event Day under the IEEE methodology.

JOINT PRE-FILED DIRECT TESTIMONY

OF

STEPHANIE A. BRIGGS AND JEFFREY D. OLIVEIRA

August 1, 2022

Table of Contents

I. Introduction

Stephanie A. Briggs

Q. Please state your full name and business address.

A. My name is Stephanie A. Briggs, and my business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Please state your position.

A. I am employed by PPL Services Corporation ("Service Corporation") as a Senior Manager Revenue. The Services Corporation provides administrative, management and support services to PPL Corporation ("PPL") and its subsidiary companies, including The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"). My current duties include responsibility for revenue requirement and rates calculations for the Company).

Q. Please describe your education and professional experience.

A. In 2000, I received a Bachelor of Arts degree in Accounting from Bryant College. In 2004, I was hired by National Grid USA Service Company, Inc. ("National Grid Service Company") as a Senior Analyst in the Accounting Department. In this position, I was responsible for supporting the books and records of National Grid USA's ("National Grid") New York affiliate. In 2009, I was promoted to Senior Analyst in National Grid's Regulatory Accounting Group. In this capacity, I supported the accounting of regulatory assets and deferrals in accordance with the rate plans and agreements applicable to National Grid's affiliated distribution operating companies. In 2011, I was promoted to Lead Specialist for Revenue Requirements responsible for supporting New York revenue requirements. In 2017, I was promoted to Director of Revenue Requirements for New York. In July 2020, I became Director of Revenue Requirements for New England. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100% of the outstanding shares of common stock of the Company from National Grid (the "Acquisition") at which time I began working in my current position.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC") or other regulatory bodies?

A. Yes. I provided pre-filed direct testimony in the Company's Annual Retail Rate Filing for 2022, Docket No. 5234 and the Company's 2021 Performance Incentive Mechanism Factor Filing, Docket No. 4770. I have also submitted pre-filed testimony to the Massachusetts Department of Public Utilities on behalf of the Company's former affiliates, Massachusetts Electric Company and Nantucket Electric Company, as a revenue requirement witness in various proceedings.

<u>Jeffrey D. Oliveira</u>

Q. Please state your full name and business address.

A. My name is Jeffrey D. Oliveira, and my business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. By whom are you employed and in what position?

A. I am employed by the Services Corporation as a Regulatory Programs Specialist. My current duties include leading the revenue requirement analyses and modeling that support regulatory filings, regulatory strategies, and rate cases for the Company.

Q. Please describe your education and professional experience.

A. In 2000, I earned an associate degree in Business Administration from Bristol Community College in Fall River, Massachusetts. I was employed by the National Grid USA Service Company, Inc. (the "Service Company") and its predecessor companies from 1999-2022. From 1999 through 2000, I was employed by Fall River Gas Company as a Staff Accountant. In 2001, after Fall River Gas Company merged with Southern Union Company, I continued as a Staff Accountant with increased responsibilities. In August of 2006, the Company acquired the Rhode Island operations of Southern Union d/b/a New England Gas Company at which time I joined the Service Company as a Senior Accounting Analyst. In January 2009, I became a Senior Revenue Requirement Analyst in the Service Company's Strategy and Regulation Department. In July 2011, I was promoted to Lead Revenue Requirement Analyst in the New England Revenue Requirements group of the New England Regulatory Department of the Service Company. Upon closing of the Acquisition, I began working in my current position.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC")?

A. Yes. I testified before the PUC in support of the Company's filings in several proceedings as follows: R.I.P.U.C Docket No. 4978 (Last Resort Service Rate Filing); R.I.P.U.C Docket 22-04-REG (Renewable Energy Growth Factor Filing); R.I.P.U.C Docket 5234 (Annual Retail Rate Filing); R.I.P.U.C Docket 4686 (Joint Petition between National Grid and the Rhode Island Division of Public Utilities and Carriers ("Division") filed February 23, 2022); R.I.P.U.C Docket 5165 (Distribution Adjustment Charge Filing, 2021); R.I.P.U.C Docket 5179 (Pension Adjustment Factor Filing, 2021); R.I.P.U.C Docket 5040 (Distribution Adjustment Charge Filing, 2020); R.I.P.U.C Docket 5054 (Pension Adjustment Factor Filing, 2020); R.I.P.U.C Docket 4955 (Distribution Adjustment Charge Filing, 2019); R.I.P.U.C Docket 4958 (Pension Adjustment Factor Filing, 2019); 4846 (Distribution Adjustment Charge Filing, 2018); R.I.P.U.C Docket 4855 (Pension Adjustment Factor Filing, 2018); and again in Docket No. 4686, in support of the Joint Proposal and Settlement submitted by the Company and the Division dated September 25, 2017 ("2017 Joint Proposal and Settlement") pertaining to the operation of the Storm Contingency Fund. I have also submitted pre-filed testimony to the

Massachusetts Department of Public Utilities on behalf of the Company's affiliates, Massachusetts Electric Company and Nantucket Electric Company, as a revenue requirement witness in annual pension adjustment mechanism proceedings.

Q. What is the purpose of your testimony?

A. In this docket, the PUC approved a new Electric ISR factor, for effect on April 1, 2021. That factor was based on a projected FY 2022 ISR revenue requirement of $41,357,719 for the estimated operation and maintenance ("O&M") work associated with the Company's vegetation management ("VM") and inspection and maintenance ("I&M") programs for the Company's FY ended March 31, 2022, on the estimated ISR plant additions during the Company's FYs ended March 31, 2022 and 2021, and on the actual ISR additions during the Company's Fiscal Years ended March 31, 2018, 2019 and 2020, which were incremental to the levels reflected in rate base in the Company's last base rate case (Docket No.4770). On September 1, 2018, new distribution base rates as approved in Docket No. 4770 became effective. The revenue requirements on actual ISR additions made from FY 2012 through FY 2017 plus forecasted ISR additions for FY 2018, FY 2019, and a portion of FY 2020 were included in these new base rates. Thus, the purpose of our testimony is to present an updated FY 2022 Electric ISR revenue requirement associated with actual FY 2022 O&M programs, the actual capital investment levels for each of FY 2018 through FY 2022 incremental to the level of investment assumed in Docket No. 4770, and actual tax deductibility percentages for FY 2021 capital additions.

The updated FY 2022 revenue requirement also includes an adjustment associated with the property tax recovery formula that was approved in Docket No. 4323 and Docket No. 4770. As the vintage years FY 2012 through FY 2017 were rolled into the base rates approved in Docket No. 4770 that became effective on September 1, 2018, the property tax recovery adjustment covers only the months of September 2018 through March 31, 2022.

As shown on Attachment SAB/JDO-1, Page 1 at Line 14, the updated FY 2022 ISR revenue requirement collectible through the Company's ISR factor for the FY 2022 period, including updated tax deductibility adjustments to the FY 2021 revenue requirement, totals $37,760,618. This is a decrease of $3,597,101 from the projected FY 2022 Electric ISR revenue requirement of $41,357,719, previously approved by the PUC in this docket. This decrease is primarily attributable to a decrease in the actual effective FY 2022 property tax rate compared with the projected effective FY 2022 property tax rate in the FY 2022 ISR Plan, also attributed by a decrease in the FY 2022 revenue requirement on a lower level of capital investment.

Q. Does the updated FY 2022 revenue requirement in this filing include an updated FY 2022 NOL utilization?

A. At this time, it is forecast that the Company will earn taxable income and utilize prior years' tax net operating losses (NOL) in FY 2022. In Docket No. 4770, the accumulated deferred income taxes included in rate base assumed estimated NOL utilization. Therefore, the difference between the newly estimated NOL utilization and the NOL utilization assumed in base rates was included in the vintage year FY 2022 ISR Plan revenue requirement based on the most recent estimate of FY 2022 tax deductibility. Actual tax deductibility percentages for FY 2022 plant additions will not be known until the Company files its FY 2022 income tax return in December of this year. Consequently, the actual tax deductibility percentages for FY 2022 plant additions have not been updated in this reconciliation and will be reflected in the Company's FY 2023 Electric ISR Reconciliation filing and will generate a true-up adjustment in that filing.

Q. Are there any schedules attached to your testimony?

A. Yes, we are sponsoring the following Attachment:

- Attachment SAB/JDO-1 FY 2022 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Revenue Requirement

II. Electric ISR FY2022 Revenue Requirement

Q. Did the Company calculate the updated FY 2022 ISR revenue requirement in the same fashion as calculated in the previous ISR Factor submissions and the August 2021 ISR factor reconciliation?

A. Yes, the Company calculated the updated FY 2022 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions. Similar to the FY 2021 filing, the calculation incorporates the approved weighted average cost of capital and depreciation rates from Docket No. 4770 and known tax deductibility percentages for FY 2021.

The updated FY 2022 ISR revenue requirement presented in this reconciliation is nearly identical to the calculated revenue requirement used to develop the approved ISR factors that became effective April 1, 2021. A detailed description of the revenue requirement calculation employed can be found in the revenue requirement testimony included in the Company's FY 2022 ISR Plan Proposal filing in this docket. For brevity, we limit this testimony to the following: (1) a description of the impact of Docket No. 4770 to the Electric ISR revenue requirement, (2) a summary of the revenue requirement update shown on Page 1 of Attachment SAB/JDO-1; and 3) a summary of FY 2021 revenue requirement income tax true-up shown on Page 1 of Attachment SAB/JDO-1 and the update for the tax deductibility percentages.

Q. Please summarize the change in the FY 2022 ISR revenue requirement proposed in this reconciliation filing as compared to the FY 2022 revenue requirement effective April 1, 2021, which was based on projected capital additions approved in the FY 2021 and FY 2022 ISR Plans.

A. As shown in Attachment SAB/JDO-1, Page 1, Line 14, column (c), the overall FY 2022 revenue requirement decrease is $3,597,101, which is the net impact of:

(1) a $0.1 million increase in the FY 2022 revenue requirement on vintage FY 2021 ISR capital additions mainly driven by the FY 2021 income tax deductibility update; (2) a $1.1 million decrease in the FY 2022 revenue requirement on vintage FY 2022 ISR capital additions mainly caused by $9.7 million lower capital investment placed into service compared to the amount approved in the FY 2022 Plan; (3) a $2.6 million decrease in the FY 2022 property tax recovery adjustment mainly driven by the lower actual tax rate in FY 2022 compared to the previous filed FY 2022 Plan; (4) a decrease of $0.83 million due to the true-up of FY 2021 revenue requirement to reflect actual tax deductibility as described in detail later in this testimony; and (5) a $0.1 million increase in O&M expense compared to the approved FY 2022 plan.

Q. Please describe the impact of the implementation of new base distribution rates that were approved by the PUC in Docket No. 4770 and put into effect on September 1, 2018 on the FY 2022 ISR revenue requirement recoverable through the FY 2022 ISR factor.

A. The ISR mechanism was established to allow the Company to recover outside of base rates, costs of capital investment in electric distribution system infrastructure, safety and reliability. When new base distribution rates are implemented, as was the case in Docket No. 4770, the costs that are recovered and associated with pre-rate case ISR capital investment cease to be recovered through a separate ISR factor. Instead, these costs are recovered through base distribution rates, and the underlying ISR capital investment becomes a component of base distribution rate base from that point forward. In November 2017, the Company filed an application with the PUC seeking a change in base distribution rates for its gas and electric distribution businesses. The proceeding culminated with the Commission's approval of a settlement agreement with the Division and numerous intervenors establishing new base distribution rates for the Company. The Company's proposed rate base reflected projected capital investments through August 31, 2019. In its base rate request, the Company proposed to maintain consistency with the existing ISR mechanism for the FY 2019, FY 2020, and FY 2021 periods. Consequently, the forecast used to develop rate base in the first year of the distribution rate case included actual capital investment through the test year ending June 30, 2017, nine months of the ISR approved capital investment levels for vintage FY 2018, 12 months of vintage FY 2019 investment and five months of vintage FY 2020 investment (using the FY 2018 ISR approved level of plant additions as a proxy for FY 2018, FY 2019, and FY 2020). The FY 2022 revenue requirement for incremental FY 2018 through FY 2022

ISR investments that are incremental to the estimated level of investment assumed in base rates reflects a full year of revenue requirement as none of these incremental investments are included in the Company's rate-base. These incremental FY vintage amounts are to remain in the ISR recovery mechanism as provided for in the terms of the Docket No. 4770 approved Settlement Agreement until a future proceeding that rolls these amounts into base rates.

Q. Please describe the calculation of the excess deferred income tax amounts.

A. As a result of the implementation of new base distribution rates pursuant to Docket No. 4770 effective September 1, 2018, the recovery of the cumulative amount of forecasted ISR capital investments was reflected in base distribution rates effective at that date. Consequently, the ISR revenue requirements after FY 2019 reflect the revenue requirement of incremental ISR investments of FY 2018 and after. Among the vintage years, only FY 2018 incremental ISR investment created excess deferred tax. The excess deferred income taxes are calculated on Line 22, Page 2 of Attachment SAB/JDO-1. The Company derived the excess deferred income tax amounts by multiplying the cumulative balance of ISR book to tax depreciation differences as of March 31, 2018 by the 10.55 percent change in the tax rate (31.55 percent average rate for FY 2018 minus 21 percent).

Q. How was the Electric ISR revenue requirement revised for the change in the bonus depreciation rules resulting from the Tax Act?

A. Bonus depreciation, sometimes known as first year bonus depreciation, is an accelerated tax depreciation method that was established first in 2002 as an economic stimulus to incent U.S. corporations to increase capital investments. Bonus depreciation allows companies to take an immediate tax deduction for some portion of certain qualified capital investments based on the bonus depreciation rates in effect for that year of investment. Bonus depreciation rates have ranged from a high of 100 percent in some years, to as low as 30 percent for calendar 2019 as was specified in the tax laws prior to the passage of the Tax Act. Pursuant to those prior tax laws, bonus depreciation was set to expire at the end of calendar year 2019. However, the Tax Act changed the rules for bonus depreciation for certain capital investments, including ISR eligible investments, effective September 28, 2017. Based on the 2017 Tax Act, property acquired prior to September 28, 2017 and placed in service during tax years beginning after December 31, 2017 are allowed bonus depreciation.

As indicated in the Company's FY 2022 ISR Plan Section 5, the Company's original interpretation of the 2017 Tax Act was that no deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. However, based on current industry practice, the Company has included actual FY 2019 and FY 2020 bonus depreciation in its calculation of accumulated deferred income taxes in the respective vintage year's rate base. The

Company's FY 2022 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2022 investments.

Q. Are there any updates to the FY 2021 revenue requirement reflected in the FY 2022 Electric ISR Reconciliation?

A. Yes. The Company filed its FY 2021 Electric ISR Reconciliation Compliance Filing on September 24, 2021. However, it had not filed its FY 2021 income tax return until later that year in the month of December. As a result, the Company used certain tax assumptions, and the Company has revised its vintage FY 2021 revenue requirement to reflect the following updates on Attachment SAB/JDO-1, Pages 13, 14, 15 and 21: (1) actual capital repairs deduction rate of 23.49 percent as shown on Attachment SAB/JDO-1, Page 14, Line 2; (2) actual tax loss on retirements of $3,539,849 as shown on Attachment SAB/JDO-1 Page 14, Line 20; and (3) actual NOL utilization of $1,695,589 as shown on Attachment SAB/JDO-1 Page 21, Line 11, column (d). The net result of these tax deductibility updates is a decrease to the FY 2021 ISR revenue requirement of $83,104, as shown on Attachment SAB/JDO-1, Page 1 at Line 11.

Q. Please summarize the updated FY 2022 ISR revenue requirement.

A. As shown on Page 1 of Attachment SAB/JDO-1, the Company's FY 2022 Electric ISR Program revenue requirement includes two elements: (1) O&M expense associated with the Company's VM activities and system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's I&M Program, and (2) the Company's capital investment in electric utility infrastructure. The description of these elements and the related amounts are supported by the direct testimony and supporting attachments of Ms. Patricia Easterly. Line 4 reflects the actual FY 2022 revenue requirement related to O&M expenses of $12,081,003.

As shown on Page 1, at Line 13 of Attachment SAB/JDO-1, the FY 2022 revenue requirement associated with the Company's actual capital investment totals $25,679,615. As previously noted, the total FY 2022 capital investment component of revenue requirement includes (1) FY 2022 revenue requirement on vintages FY 2018 through FY 2022 ISR capital investments above or below the level of capital investment reflected in base distribution rates in Docket No. 4770; (2) the FY 2022 property tax recovery mechanism component; and (3) the FY 2021 revenue requirement true-up for changes to previously estimated tax depreciation expense and NOL position to align with the Company's FY 2021 tax return, which was filed in December 2021. The total actual FY 2022 ISR Plan revenue requirement for both O&M expenses and capital investment of $37,760,618 is shown on Line 14.

Q. Please describe how the attachment to your testimony is structured.

A. Page 1 of Attachment SAB/JDO-1 summarizes the individual components of the updated FY 2022 ISR revenue requirement. Page 1, Column (a) reflects the approved FY 2022

Electric ISR Plan revenue requirement on projected VM and I&M program costs and incremental ISR capital investment as well as the projected FY 2022 property tax recovery adjustment. Page 1, Column (b) represents (1) the O&M components for FY 2022; (2) FY 2022 ISR revenue requirements for incremental FY 2018 through FY 2022 ISR investments – not included in the Company's base rates in Docket No. 4770– and as supported with detailed calculations on Attachment SAB/JDO-1, Pages 2, 5, 10, 13 and 18; (3) FY 2022 property tax adjustment on incremental capital not included in the Company's base rates in Docket No. 4770; and (4) Line 12 reflects the reconciliation of the approved FY 2021 ISR revenue requirement for vintage FY 2021 plant additions with the actual vintage FY 2021 revenue requirement on those investments. As previously discussed, this reconciliation is necessary because the actual level of tax deductibility on FY 2021 investments was not known when the Company filed the FY 2021 ISR reconciliation and FY 2022 ISR Plan proposals. A detailed calculation of the updated FY 2021 revenue requirement is presented on page 13 of Attachment SAB/JDO-1.

Q. Has the Company provided support for the actual level of FY 2022 ISR-eligible plant investments?

A. Yes. The description of the FY 2022 Electric ISR program and the amount of the incremental plant additions eligible for inclusion in the ISR mechanism are supported by the direct testimony and supporting attachment of Ms. Easterly. The ultimate revenue requirement on the ISR eligible plant additions equals the return on the investment (i.e., average rate base at the weighted average cost of capital), plus depreciation expense and property taxes associated with the investment. Incremental ISR eligible plant additions for this purpose are intended to represent the net change in rate base for electric infrastructure investments, since the establishment of the Company's ISR mechanism effective April 1, 2011 and are defined as capital additions plus cost of removal, less annual depreciation expense included in the Company's rates, net of depreciation expense attributable to general plant. As discussed in the testimony of Ms. Easterly, the actual ISR eligible plant additions for FY 2022 totals $88.8 million associated with the Company's FY 2022 ISR Plan (electric infrastructure investment net of general plant).

Q. Please explain the distinction between non-discretionary and discretionary capital spending as they relate to the revenue requirement calculation.

A. For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: (1) non-discretionary capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations; and (2) discretionary capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined non-discretionary categories. The amount of discretionary investment the Company is allowed to include in the revenue requirement calculation is subject to certain limitations. The amount of discretionary capital investment the Company uses in the revenue requirement must be no greater than the cumulative amount of discretionary project spend as approved by the PUC in this proceeding. This means that the discretionary investment is limited to the lesser of actual cumulative discretionary capital additions or spending, or cumulative discretionary spending approved by the PUC in this docket. For purposes of the FY 2022 revenue requirement, the lesser of these items was actual discretionary capital additions of $42,200,430, as shown on Attachment SAB/JDO-1, Page 29, Line 13, column (a), of which $42,200,430 was incremental to the amount of discretionary capital additions assumed in base rates.

Q. What is the updated revenue requirement associated with actual plant additions?

A. The updated FY 2022 revenue requirement, associated with the Company's actual FY 2018 through FY 2022 ISR eligible plant investments, totals $37,760,618. This amount includes the updated FY 2022 O&M components and revenue requirement on FY 2018 through FY 2022 incremental ISR investments, inclusion of the property tax recovery adjustment pursuant to the rate case settlement agreements in Docket No. 4323 and in Docket No. 4770, and the reconciliation of the approved FY 2021 ISR revenue requirements on vintage FY 2021 investments with the actual FY 2021 income tax deductibility on those investments.

III. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

Index of Attachments

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2022 Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2022 (a)	Actual Fiscal Year 2022 (b)	Variance Fiscal Year 2022 (c)=(b)-(a)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$10,800,000	$11,261,563	$461,563
2	Current Year Inspection & Maintenance (I&M)	$896,000	$611,933	($284,067)
3	Current Year Other Programs	$287,000	$207,507	($79,493)
4	**Total O&M Expense Component of Revenue Requirement**	**$11,983,000**	**$12,081,003**	**$98,003**
	Capital Investment:			
5	Actual 2022 Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$2,001,528	$2,001,528	$0
6	Actual 2022 Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$4,115,670	$4,115,670	$0
7	Actual 2022 Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$5,902,936	$5,902,936	$0
8	Actual 2022 Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base	$8,723,827	$8,811,885	$88,058
9	Actual 2022 Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base	$3,589,630	$2,493,373	($1,096,257)
10	Subtotal	$24,333,591	$23,325,392	($1,008,199)
11	FY 2022 Property Tax Recovery Adjustment	$5,041,128	$2,437,327	($2,603,801)
12	True-Up for FY 2021 (Income Tax)		($83,104)	($83,104)
13	**Total Capital Investment Component of Revenue Requirement**	**$29,374,719**	**$25,679,615**	**($3,695,104)**
14	**Total Fiscal Year Revenue Requirement**	**$41,357,719**	**$37,760,618**	**($3,597,101)**
15	**Incremental Fiscal Year Rate Adjustment**		**($3,597,101)**	

Column/Line Notes:

Col (a)	Docket No. 5098, FY 2022 Electric ISR Plan, Revised Section 5: Attachment 1C, Page 1 of 29, Column (b)
Col (b)	
1	Vegetation Management, Section 4, Table 10
2	Other Operations and Maintenance, Section 5, Table 11
3	Other Operations and Maintenance, Section 5, Table 11
4	Sum of Lines 1 through 3
5	Page 2 of 29, Line 34 column (f)
6	Page 5 of 29, Line 36, Column (e)
7	Page 10 of 29, Line 33, Column (d)
8	Page 13 of 29, Line 34, Column (c)
9	Page 18 of 29, Line 33, Column (b)
10	Sum of Lines 5 through 9
11	Page 26 of 29, Line 55, Column (r) x 1,000
12	Page 13 of 29, Line 36, Column (a)
13	Sum of Lines 10 through 12
14	Line 4 + Line 13
15	Line 14 Col (b) - Line 14 Col (a)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
FY 2022 Revenue Requirement on FY 2018 Actual Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*			$3,178,398				
	Discretionary Capital							
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$14,638,256				
3	Total Allowed Capital Included in Rate Base	Page 21 of 29, Line 4(a)		$17,816,654	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$17,816,654	$0	$0	$0	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (a)		($5,245,072)	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726
	Change in Net Capital Included in Rate Base							
7	Capital Included in Rate Base	Line 3		$17,816,654	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (a)		$1,719,991	$0	$0	$0	$0
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**
	Deferred Tax Calculation:							
12	Composite Book Depreciation Rate		1/	3.40%	3.26%	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:							
14	2018 Spend	Year 1 = Page 3 of 29, Line 23; then = Page 3 of 29, Column (b)		$13,898,861	$571,028	$528,156	$488,605	$451,903
15	Cumulative Tax Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14		$13,898,861	$14,469,889	$14,998,045	$15,486,650	$15,938,553
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12		$392,049	$751,812	$728,751	$728,751	$728,751
17	Cumulative Book Depreciation	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$392,049	$1,143,862	$1,872,612	$2,601,363	$3,330,113
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$13,506,812	$13,326,028	$13,125,433	$12,885,287	$12,608,439
19	Effective Tax Rate		2/	21.00%	21.00%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$2,836,430	$2,798,466	$2,756,341	$2,705,910	$2,647,772
21	Less: FY 2018 Federal NOL	Year 1 = Page 21 of 29 , Line 15 ,Col (a) ; then = Prior Year Line 21		($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)
22	Excess Deferred Tax	Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1		$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969
23	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 22		$1,262,901	$1,224,936	$1,182,811	$1,132,380	$1,074,242
	Rate Base Calculation:							
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645
25	Accumulated Depreciation	-Line 17		($392,049)	($1,143,862)	($1,872,612)	($2,601,363)	($3,330,113)
26	Deferred Tax Reserve	-Line 23		($1,262,901)	($1,224,936)	($1,182,811)	($1,132,380)	($1,074,242)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$17,881,695	$17,167,848	$16,481,222	$15,802,902	$15,132,290
	Revenue Requirement Calculation:							
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 and 2 = 0; then Average of (Prior + Current Year Line 27)						$15,467,596
29	Proration Adjustment	Year 1 - Year 5 = 0; Y 6 = Page 4 of 29, Line 41(g) through (h)						($2,495)
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29						$15,465,101
31	Pre-Tax ROR	Page 28 of 29, Line 35						8.23%
32	Return and Taxes	Line 30 * Line 31						$1,272,778
33	Book Depreciation	Line 16						$728,751
34	**Annual Revenue Requirement**	Line 32 + Line 33		**$0**	**$0**	**$0**	**$0**	**$2,001,528**

1/ 3.4%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
3.16%, Composite Book Depreciation Rate for ISR plant, approved per RIPUC Docket No. 4770, effective on Sep 1, 2018, per Page 12 of 18
FY 19 Composite Book Depreciation Rate = 3.4% x 5 /12 + 3.16% x 7 / 12
2/ The Federal Income Tax rate changed from 35% to 21% on Janurary 1, 2018 per the Tax Cuts and Jobs Act of 2017

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2018 Incremental Capital Investments

Line No.				Fiscal Year 2018 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 2 of 29, Line 3		$17,816,654
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.00%
3	Capital Repairs Deduction	Line 1 * Line 2		$1,603,499
	Bonus Depreciation			
4	Plant Additions	Line 1		$17,816,654
5	Less Capital Repairs Deduction	- Line 3		($1,603,499)
6	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5		$16,213,155
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$16,213,155
9	Bonus depreciation 100% category	100% * 16.38%	2/	16.38%
10	Bonus depreciation 50% category	50% * 34.28%	2/	17.14%
11	Bonus depreciation 40% category	40% * 44.23%	2/	17.69%
12	Bonus depreciation 0% category	0% * 5.11%	2/	0.00%
13	Total Bonus Depreciation Rate	Line 9 + Line 10 + Line 11 + Line 12		51.21%
14	Bonus Depreciation	Line 8 * Line 13		$8,303,081
	Remaining Tax Depreciation			
15	Plant Additions	Line 1		$17,816,654
16	Less Capital Repairs Deduction	Line 3		$1,603,499
17	Less Bonus Depreciation	Line 14		$8,303,081
18	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 15 - Line 16 - Line 17		$7,910,074
19	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
20	Remaining Tax Depreciation	Line 18 * Line 19		$296,628
21	FY18 Loss incurred due to retirements	Per Tax Department	3/	$1,975,662
22	Cost of Removal	Page 2 of 29, Line 10		$1,719,991
23	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 20, 21, and 22		$13,898,861

20 Year MACRS Depreciation

MACRS basis: Line 18 $7,910,074

(b) Fiscal Year	(c)	(d) Annual MACRS	(e) Cumulative Tax Depr
2018	3.750%	$296,628	$13,898,861
2019	7.219%	$571,028	$14,469,889
2020	6.677%	$528,156	$14,998,045
2021	6.177%	$488,605	$15,486,650
2022	5.713%	$451,903	$15,938,553
2023	5.285%	$418,047	$16,356,600
2024	4.888%	$386,644	$16,743,245
2025	4.522%	$357,694	$17,100,938
2026	4.462%	$352,948	$17,453,886
2027	4.461%	$352,868	$17,806,754
2028	4.462%	$352,948	$18,159,702
2029	4.461%	$352,868	$18,512,570
2030	4.462%	$352,948	$18,865,518
2031	4.461%	$352,868	$19,218,386
2032	4.462%	$352,948	$19,571,334
2033	4.461%	$352,868	$19,924,202
2034	4.462%	$352,948	$20,277,149
2035	4.461%	$352,868	$20,630,018
2036	4.462%	$352,948	$20,982,965
2037	4.461%	$352,868	$21,335,834
2038	2.231%	$176,474	$21,512,308
	100.00%	$7,910,074	

1/ Capital Repairs percentage is based on the actual results of the FY 2018 tax return.
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY2018 tax return
3/ Actual Loss for FY2018

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment

Line No.			(a) FY22
	Deferred Tax Subject to Proration		
1	Book Depreciation	Page 2 of 29, Line 33	$728,751
2	Bonus Depreciation		$0
3	Remaining MACRS Tax Depreciation	Page 3 of 29, Line 8, column, (d)	($451,903)
4	FY18 tax (gain)/loss on retirements		$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$276,848
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$58,138
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction		
9	Cost of Removal		
10	Book/Tax Depreciation Timing Difference at 3/31/2017		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	
12	Effective Tax Rate		
13	Deferred Tax Reserve	Line 11 × Line 12	
14	Total Deferred Tax Reserve	Line 7 + Line 13	$58,138
15	Net Operating Loss		$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$58,138
	Allocation of FY 2018 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$276,848
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$276,848
20	Total FY 2018 Federal NOL		
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0
22	Allocated FY 2018 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$58,138

		(d)	(e)	(f)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY22
26	April	30	91.78%	$4,447
27	May	31	83.29%	$4,035
28	June	30	75.07%	$3,637
29	July	31	66.58%	$3,225
30	August	31	58.08%	$2,814
31	September	30	49.86%	$2,416
32	October	31	41.37%	$2,004
33	November	30	33.15%	$1,606
34	December	31	24.66%	$1,195
35	January	31	16.16%	$783
36	February	28	8.49%	$411
37	March	31	0.00%	$0
38	Total	365		$26,574
39	Deferred Tax Without Proration	Line 25		$58,138
40	Average Deferred Tax without Proration	Line 25 * 50%		$29,069
41	Proration Adjustment	Line 38 - Line 40		($2,495)

Column Notes:
(e) Sum of remaining days in the year (Col (d)) ÷ 365
(g) through (h) Current Year Line 25 ÷ 12 × Current Month Col (e)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
FY 2022 Revenue Requirement on FY 2019 Actual Incremental Capital Investment

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)	Fiscal Year 2022 (d)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*			$7,452,659		$0	$0
	Discretionary Capital						
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$25,486,776		$0	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 21 of 29, Line 4(b)		$32,939,435	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3, Column (a)		$32,939,435	$0	$0	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (b)		($10,649,479)	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$43,588,914	$43,588,914	$43,588,914	$43,588,914
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3, Column (a)		$32,939,435	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9		$32,939,435	$32,939,435	$32,939,435	$32,939,435
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (b)		$101,073			
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	As approved per RIPUC Docket No. 4323 and Docket No. 4770	1/	3.26%	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:						
14	2019 Spend	Year 1 = Page 6 of 29, Line 22 Then = Page 6 of 29 Column (b)		$9,919,837	$1,842,847	$1,704,487	$1,576,848
15	Cumulative Tax Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14		$9,919,837	$11,762,684	$13,467,171	$15,044,019
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$710,499	$1,377,410	$1,377,410	$1,377,410
17	Cumulative Book Depreciation	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$710,499	$2,087,909	$3,465,319	$4,842,728
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$9,209,338	$9,674,775	$10,001,852	$10,201,291
19	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$1,933,961	$2,031,703	$2,100,389	$2,142,271
21	Add: FY 2019 Federal NOL incremental utilization	Page 21 of 29 , Line 15 ,Col (b)		$991,622	$991,622	$991,622	$991,622
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21		$2,925,583	$3,023,325	$3,092,011	$3,133,893
	Rate Base Calculation:						
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$33,040,508	$33,040,508	$33,040,508	$33,040,508
24	Accumulated Depreciation	-Line 17		($710,499)	($2,087,909)	($3,465,319)	($4,842,728)
25	Deferred Tax Reserve	-Line 22		($2,925,583)	($3,023,325)	($3,092,011)	($3,133,893)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$29,404,426	$27,929,274	$26,483,178	$25,063,887
	Revenue Requirement Calculation:						
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 26 ÷ 2; Then = (Prior Year Line 26 + Current Year Line 26) ÷ 2					$25,773,533
28	Proration Adjustment	Page 7 of 29, Line 41, Column (g) ~ (h)					($339)
29	Average ISR Rate Base after Deferred Tax Proration	Line 27 + Line 28					$25,773,194
30	Pre-Tax ROR	Page 28 of 29, Line 35					8.23%
31	Return and Taxes	Line 29 * Line 30					$2,121,134
32	Book Depreciation	Line 16					$1,377,410
33	Annual Revenue Requirement	Line 31 + Line 32					$3,498,544
34	Revenue Requirement of Plant	Year 1 = Line 33*7/12, Then = Line 33					$3,498,544
35	Revenue Requirement of Intangible	Page 8 of 29, Line 30, Column (f)~ (l)					$617,127
36	**Revenue Requirement**	Line 34 + Line 35		**N/A**	**N/A**	**N/A**	**$4,115,670**

1/ 3.4%, Composite Book Depreciation Rate approved per RIPUC Docket No. 4323, in effect until Aug 31, 2018
3.16%, Composite Book Depreciation Rate for ISR plant, approved per RIPUC Docket No. 4770, effective on Sep 1, 2018
FY 19 Composite Book Depreciation Rate = 3.4% x 5 /12 + 3.16% x 7 / 12

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2019 Incremental Capital Investments

Line No.				Fiscal Year 2019 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 5 of 29, Line 3		$32,939,435
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.68%
3	Capital Repairs Deduction	Line 1 * Line 2		$3,188,562
	Bonus Depreciation			
4	Plant Additions	Line 1		$32,939,435
5	Plant Additions			$0
6	Less Capital Repairs Deduction	Line 3		$3,188,562
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$29,750,873
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$29,750,873
10	Bonus Depreciation Rate	1 * 11.65% * 30%	2/	3.50%
11	Bonus Depreciation Rate	1 * 26.75% * 40%	2/	10.70%
12	Total Bonus Depreciation Rate	Line 10 + Line 11		14.20%
13	Bonus Depreciation	Line 9 * Line 12		$4,223,136
	Remaining Tax Depreciation			
14	Plant Additions	Line 1		$32,939,435
15	Less Capital Repairs Deduction	Line 3		$3,188,562
16	Less Bonus Depreciation	Line 13		$4,223,136
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$25,527,737
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
19	Remaining Tax Depreciation	Line 17 * Line 18		$957,290
20	FY19 (Gain)/Loss incurred due to retirements	Per Tax Department	3/	$1,449,776
21	Cost of Removal	Page 5 of 29, Line 10		$101,073
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$9,919,837

20 Year MACRS Depreciation

MACRS basis: Line 17 $25,527,737

(b) Fiscal Year	(c)	(d) Annual	(e) Cumulative
2019	3.750%	$957,290	$9,919,837
2020	7.219%	$1,842,847	$11,762,684
2021	6.677%	$1,704,487	$13,467,171
2022	6.177%	$1,576,848	$15,044,019
2023	5.713%	$1,458,400	$16,502,419
2024	5.285%	$1,349,141	$17,851,560
2025	4.888%	$1,247,796	$19,099,356
2026	4.522%	$1,154,364	$20,253,720
2027	4.462%	$1,139,048	$21,392,768
2028	4.461%	$1,138,792	$22,531,560
2029	4.462%	$1,139,048	$23,670,608
2030	4.461%	$1,138,792	$24,809,400
2031	4.462%	$1,139,048	$25,948,447
2032	4.461%	$1,138,792	$27,087,240
2033	4.462%	$1,139,048	$28,226,287
2034	4.461%	$1,138,792	$29,365,080
2035	4.462%	$1,139,048	$30,504,127
2036	4.461%	$1,138,792	$31,642,920
2037	4.462%	$1,139,048	$32,781,967
2038	4.461%	$1,138,792	$33,920,760
2039	2.231%	$569,524	$34,490,284
	100.00%	$25,527,737	

1/ Capital Repairs percentage is the actual result of FY 2019 tax return
2/ Percent of Plant Eligible for Bonus Depreciation is the actual result of FY 2019 tax return
3/ Actual Loss for FY 2019

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment

Line No.	Deferred Tax Subject to Proration		(a) FY22
1	Book Depreciation	Page 5 of 29, Line 32 + (Page 8 of 29, Line 19- Line 18)	$1,871,785
2	Bonus Depreciation		$0
3	Remaining MACRS Tax Depreciation	Page 6 of 29, Line 8, column, (d)	($1,833,281)
4	FY 2019 tax (gain)/loss on retirements		$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$38,504
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$8,086
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction		
9	Cost of Removal		
10	Book/Tax Depreciation Timing Difference at 3/31/2018		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21%
13	Deferred Tax Reserve	Line 11 × Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	$8,086
15	Net Operating Loss		$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$8,086
	Allocation of FY 2019 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$38,504
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$38,504
20	Total FY 2019 Federal NOL		$0
21	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0
22	Allocated FY 2019 Federal NOL Subject to Proration	(Line 17 ÷ Line 19) × Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 × Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$8,086

Line No.	Proration Calculation	(d) Number of Days in Month	(e) Proration Percentage	(f0 FY23
26	April	30	91.80%	$619
27	May	31	83.33%	$562
28	June	30	75.14%	$506
29	July	31	66.67%	$449
30	August	31	58.20%	$392
31	September	30	50.00%	$337
32	October	31	41.53%	$280
33	November	30	33.33%	$225
34	December	31	24.86%	$168
35	January	31	16.39%	$110
36	February	29	8.47%	$57
37	March	31	0.00%	$0
38	Total	366		$3,704
39	Deferred Tax Without Proration	Line 25		$8,086
40	Average Deferred Tax without Proration	Line 39 * 50%		$4,043
41	Proration Adjustment	Line 38 - Line 40		($339)

Column Notes:
(e) Sum of remaining days in the year (Col (d)) ÷ 365
(g) through (h) Current Year Line ÷ 12 × Current Month Col (e)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
FY 2022 Revenue Requirement on FY 2019 Intangible Investment

Line No.		Reference	FY19 Total (c) = (a) + (b)	FY 20 Total (f) = (d) + (e)	FY 21 Total (i) = (g) + (h)	FY 22 Total (l) = (j) + (k)
	Capital Investment					
1	Start of Rev. Req. Period		09/01/18	04/01/19	04/01/20	04/01/21
2	End of Rev. Req. Period		03/31/19	03/31/20	03/31/21	03/31/22
3	Investment Name	Per Company's Book				
4	Work Order	Per Company's Book				
5	Total Spend		$3,460,626	$3,460,626	$3,460,626	$3,460,626
6	In ServiceDate	Per Company's Book				
7	Book AmortizationPeriod	Per Company's Book				
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$3,378,230	$3,089,845	$2,595,470	$2,101,094
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$3,089,845	$2,595,470	$2,101,094	$1,606,719
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$3,234,038	$2,842,657	$2,348,282	$1,853,907
	Deferred Tax Calculation:					
11	Tax Amortizaton Period	Page 9 of 29				
12	Tax Expensing	Per Tax Department	$0	$0	$0	$0
13	Tax Bonus Rate	Per Tax Department				
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 0	$0	$0	$0	$0
15	Beginning Acc. Tax Balance	(L. 5 - L. 12- L.14)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%)	$1,153,427	$1,153,427	$2,691,675	$3,204,194
16	Ending Acc. Tax Balance	(L. 5 - L. 12- L.14) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$1,153,427	$2,691,675	$3,204,194	$3,460,626
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$1,153,427	$1,922,551	$2,947,934	$3,332,410
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$82,396	$370,781	$865,157	$1,359,532
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$370,781	$865,157	$1,359,532	$1,853,907
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$226,589	$617,969	$1,112,344	$1,606,719
21	Average Book / Tax Timer	Line 17 - Line 20	$926,838	$1,304,582	$1,835,590	$1,725,691
22	Effective Tax Rate					
23	Deferred Tax Reserve	Line 21 × Line 22	$194,636	$273,962	$385,474	$362,395
	Rate Base Calculation:					
24	Average Book Balance	Line 10	$3,234,038	$2,842,657	$2,348,282	$1,853,907
25	Deferred Tax Reserve	Line 23	$194,636	$273,962	$385,474	$362,395
26	Average Rate Base	Line 24 - Line 25	$3,039,402	$2,568,695	$1,962,808	$1,491,512
	Revenue Requirement Calculation:					
27	Pre-Tax ROR	year 1 = Page 28 of 29, Line 27, column (e)×7÷12 Then = Page 28 of 29, Line 27(e)				
28	Return and Taxes	Line 26 × Line 27	$145,917	$211,404	$161,539	$122,751
29	Book Depreciation	Line 9 - Line 8	$288,386	$494,375	$494,375	$494,375
30	Annual Revenue Requirement	Line 28 + Line 29	$434,302	$705,779	$655,914	$617,127

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
MACRS Tables For Information Systems

Line No.	Annual Rate: Year			Monthly Cumulative Rate: Year	Period	Cumulative Rate		
1	Yr 1	33.33%	33.33%	1	1	33.33%	2.78%	Yr 1 - Monthly rate
2	Yr 2	44.45%	77.78%	1	2	33.33%		
3	Yr 3	14.81%	92.59%	1	3	33.33%		
4	Net Salvage Value	7.41%	100.00%	1	4	33.33%		
11				1	11	33.33%		
12				1	12	33.33%		
13				2	13	77.78%	3.70%	Yr 2 - Monthly rate
25				3	25	92.59%	1.23%	Yr 3 - Monthly rate
36				3	36	92.59%	0.62%	Yr 3 - Monthly rate
48				4	48	100.00%		
60				5	60	100.00%		
72				6	72	100.00%		
84				7	84	100.00%		
96				8	96	100.00%		
108				9	108	100.00%		
120				10	120	100.00%		
132				11	132	100.00%		
144				12	144	100.00%		
156				13	156	100.00%		
168				14	168	100.00%		
180				15	180	100.00%		
192				16	192	100.00%		
204				17	204	100.00%		
216				18	216	100.00%		
228				19	228	100.00%		
240				20	240	100.00%		
252				21	252	100.00%		
264				22	264	100.00%		
276				23	276	100.00%		
288				24	288	100.00%		
300				25	300	100.00%		

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
FY 2022 Revenue Requirement on FY 2020 Actual Incremental Capital Investment

Line No.				Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)
	Capital Investment Allowance					
1	*Non-Discretionary Capital*			$32,485,802	$0	$0
2	*Discretionary Capital* Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$39,597,335	$0	$0
3	Total Allowed Capital Included in Rate Base	Page 21 of 29, Line 4(c)		$72,083,137	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$72,083,137	$0	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (c)		$4,015,632	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$68,067,505	$68,067,505	$68,067,505
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$72,083,137	$0	$0
8	Depreciation Expense	Page 25 of 29, Line 41, Col (d) ×7 ÷12		$29,112,370	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$42,970,767	$42,970,767	$42,970,767
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (c)		$10,949,557		
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$53,920,323**	**$53,920,323**	**$53,920,323**
	Deferred Tax Calculation:					
12	Composite Book Depreciation Rate	Page 23 of 29, Line 3, Col (e)	1/	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:					
14	2020 Spend	Year 1 = Page 11 of 29, Line 22, Then = Page 11 of 29, Column (d)		$23,811,948	$4,602,526	$4,256,970
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$23,811,948	$28,414,474	$32,671,444
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,075,467	$2,150,933	$2,150,933
17	Cumulative Book Depreciation	Year 1 = Line 16; Then = Prior Year Line 17 + Current Year Line 16		$1,075,467	$3,226,400	$5,377,333
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$22,736,481	$25,188,074	$27,294,111
19	Effective Tax Rate			21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$4,774,661	$5,289,496	$5,731,763
21	Add: FY 2020 Federal NOL Utilization	Page 21 of 29, Line 15, Col (c)		($1,462,980)	($1,462,980)	($1,462,980)
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21		$3,311,681	$3,826,515	$4,268,783
	Rate Base Calculation:					
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$53,920,323	$53,920,323	$53,920,323
24	Accumulated Depreciation	-Line 17		($1,075,467)	($3,226,400)	($5,377,333)
25	Deferred Tax Reserve	-Line 22		($3,311,681)	($3,826,515)	($4,268,783)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$49,533,176	$46,867,408	$44,274,208
	Revenue Requirement Calculation:					
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 26 * Page 17 of 29, Line 16, Col(e); Then =(Prior Year Line 26 + Current Year Line 26) ÷ 2				$45,570,808
28	Proration Adjustment	Page 12 of 29, Line 41, Column (g)				$18,529
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29				$45,589,337
30	Pre-Tax ROR	Page 28 of 29, Line 35				8.23%
31	Return and Taxes	Line 29 * Line 30				$3,752,002
32	Book Depreciation	Line 16				$2,150,933
33	**Annual Revenue Requirement**	Line 31 + Line 32		**N/A**	**N/A**	**$5,902,936**
34	Docket No. 4915, FY 2020 Electric ISR Reconciliation, Page 9, Line 29					
35	2020 Tax True Up					

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 23 of 29, Line 3, Col (e))

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2020 Incremental Capital Investments

Line No.				Fiscal Year 2020 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 10 of 29, Line 3		$72,083,137
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%
3	Capital Repairs Deduction	Line 1 * Line 2		$6,134,275
	Bonus Depreciation			
4	Plant Additions	Line 1		$72,083,137
5	Plant Additions			$0
6	Less Capital Repairs Deduction	Line 3		$6,134,275
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$65,948,862
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$65,948,862
10	Bonus Depreciation Rate	1 * 14.78% * 30% * 75%	2/	3.33%
11	Bonus Depreciation Rate	1 * 0% * 25%		0.00%
12	Total Bonus Depreciation Rate	Line 10 + Line 11		3.33%
13	Bonus Depreciation	Line 9 * Line 12		$2,193,129
	Remaining Tax Depreciation			
14	Plant Additions	Line 1		$72,083,137
15	Less Capital Repairs Deduction	Line 3		$6,134,275
16	Less Bonus Depreciation	Line 13		$2,193,129
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$63,755,733
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
19	Remaining Tax Depreciation	Line 17 * Line 18		$2,390,840
20	FY20 Loss incurred due to retirements	Per Tax Department	3/	$2,144,147
21	Cost of Removal	Page 10 of 29, Line 10		$10,949,557
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$23,811,948

20 Year MACRS Depreciation

MACRS basis: Line 17 $63,755,733

(b) Fiscal Year	(c)	(d) Annual	(e) Cumulative
2020	3.750%	$2,390,840	$23,811,948
2021	7.219%	$4,602,526	$28,414,474
2022	6.677%	$4,256,970	$32,671,444
2023	6.177%	$3,938,192	$36,609,636
2024	5.713%	$3,642,365	$40,252,001
2025	5.285%	$3,369,490	$43,621,491
2026	4.888%	$3,116,380	$46,737,872
2027	4.522%	$2,883,034	$49,620,906
2028	4.462%	$2,844,781	$52,465,687
2029	4.461%	$2,844,143	$55,309,830
2030	4.462%	$2,844,781	$58,154,611
2031	4.461%	$2,844,143	$60,998,754
2032	4.462%	$2,844,781	$63,843,535
2033	4.461%	$2,844,143	$66,687,678
2034	4.462%	$2,844,781	$69,532,459
2035	4.461%	$2,844,143	$72,376,602
2036	4.462%	$2,844,781	$75,221,383
2037	4.461%	$2,844,143	$78,065,526
2038	4.462%	$2,844,781	$80,910,307
2038	4.461%	$2,844,143	$83,754,450
2039	2.231%	$1,422,390	$85,176,840
	100.00%	$63,755,733	

1/ Per Tax Department
2/ Per Tax Department
3/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investment

Line No.			(a) FY22
	Deferred Tax Subject to Proration		
1	Book Depreciation	Page 10 of 29, Line 16	$2,150,933
2	Bonus Depreciation		$0
3	Remaining MACRS Tax Depreciation	Page 11 of 29, Line 6, col (d)	($4,256,970)
4	FY 2020 tax (gain)/loss on retirements	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,106,037)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($442,268)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0	
9	Cost of Removal	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0	
10	Book/Tax Depreciation Timing Difference at 3/31/2020		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($442,268)
15	Net Operating Loss	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($442,268)
	Allocation of FY 2020 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5	($2,106,037)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($2,106,037)
20	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)	$0
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0
23	Effective Tax Rate		21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($442,268)

Line No.		(d) Number of Days in Month	(e) Proration Percentage	(f) FY22
	Proration Calculation			
26	April	30	91.80%	($33,835)
27	May	31	83.33%	($30,713)
28	June	30	75.14%	($27,692)
29	July	31	66.67%	($24,570)
30	August	31	58.20%	($21,449)
31	September	30	50.00%	($18,428)
32	October	31	41.53%	($15,306)
33	November	30	33.33%	($12,285)
34	December	31	24.86%	($9,164)
35	January	31	16.39%	($6,042)
36	February	29	8.47%	($3,122)
37	March	31	0.00%	$0
38	Total	366		($202,605)
39	Deferred Tax Without Proration	Line 25		($442,268)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 17 of 29, Line 16, Col (e); then = Line 39 * 50%		($221,134)
41	Proration Adjustment	Line 38 - Line 40		$18,529

Column Notes:

(e) Sum of remaining days in the year (Col (d)) ÷ 365

(g) Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (j)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
FY 2022 Revenue Requirement on FY 2021 Actual Incremental Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*			$36,445,546	
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)			$80,041,254	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 21 of 29, Line 4(d)		$116,486,800	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$116,486,800	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (d)		$21,996,026	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$94,490,774	$94,490,774
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$116,486,800	$0
8	Depreciation Expense	Page 25 of 29, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920	
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$66,579,879	$66,579,879
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (d)		$11,093,804	$11,093,804
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$77,673,683**	**$77,673,683**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	Page 23 of 29, Line 3, Col (e)	1/	3.16%	3.16%
13	Vintage Year Tax Depreciation:				
14	2021 Spend	Year 1 = Page 14 of 29, Line 22, Column (a), Then = Line Page 14 of 29 , Column (d)		$45,333,033	$6,434,279
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$45,333,033	$51,767,312
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,492,954	$2,985,908
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,492,954	$4,478,863
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$43,840,079	$47,288,449
19	Effective Tax Rate			21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$9,206,417	$9,930,574
21	Add: FY 2021 Federal (NOL) Utilization	Page 21 of 29, Line 15, Col (d)		($5,639,147)	($5,639,147)
22	Net Deferred Tax Reserve beforee Proration Adjustment	Sum of Lines 20 through 21		$3,567,269	$4,291,427
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$77,673,683	$77,673,683
24	Accumulated Depreciation	-Line 17		($1,492,954)	($4,478,863)
25	Deferred Tax Reserve	-Line 22		($3,567,269)	($4,291,427)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$72,613,460	$68,903,394
	Revenue Requirement Calculation:				
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 26 * 50%; Then = (Prior Year Line 26 + Current Year Line 26) ÷ 2		$36,306,730	$70,758,427
28	Proration Adjustment	Page 15 of 29, Line 41		$16,670	$31,083
29	Average ISR Rate Base after Deferred Tax Proration	Line 27 + Line 28		$36,323,400	$70,789,509
30	Pre-Tax ROR	Page 28 of 29, Line 35		8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30		$2,989,416	$5,825,977
32	Book Depreciation	Line 16		$1,492,954	$2,985,908
33	Revenue Requirement of Intangible Assets	Page 16 of 29 Line 30 Column (a) ~ (b)		$0	$0
34	**Annual Revenue Requirement**	**Line 31 + Line 32 + Line 33**		**$4,482,370**	**$8,811,885**
35	Docket No. 4995, FY 2021 Electric ISR Reconciliation, Page 13, Line 34			$4,565,474	
36	2021 Tax True Up			($83,104)	

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 23 of 29, Line 3, Col (e))

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2021 Incremental Capital Investments

Line No.				Fiscal Year 2021 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 13 of 29, Line 3(a)		$116,486,800	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	23.49%				
					MACRS			
3	Capital Repairs Deduction	Line 1 * Line 2		$27,357,013	basis:	Line 17	$89,129,787	
							Annual	Cumulative
	Bonus Depreciation				Fiscal Year			
4	Plant Additions	Line 1		$116,486,800	2021	3.750%	$3,342,367	$45,333,033
5	Plant Additions			$0	2022	7.219%	$6,434,279	$51,767,312
6	Less Capital Repairs Deduction	Line 3		$27,357,013	2023	6.677%	$5,951,196	$57,718,508
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$89,129,787	2024	6.177%	$5,505,547	$63,224,055
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	2025	5.713%	$5,091,985	$68,316,040
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$0	2026	5.285%	$4,710,509	$73,026,549
10	Bonus Depreciation Rate	1 * 14.78% * 75% * 30%		0.00%	2027	4.888%	$4,356,664	$77,383,213
11	Bonus Depreciation Rate	1 * 25% * 0%		0.00%	2028	4.522%	$4,030,449	$81,413,662
12	Total Bonus Depreciation Rate	Line 10 + Line 11		0.00%	2029	4.462%	$3,976,971	$85,390,633
13	Bonus Depreciation	Line 9 * Line 12		$0	2030	4.461%	$3,976,080	$89,366,713
					2031	4.462%	$3,976,971	$93,343,684
	Remaining Tax Depreciation				2032	4.461%	$3,976,080	$97,319,764
14	Plant Additions	Line 1		$116,486,800	2033	4.462%	$3,976,971	$101,296,735
15	Less Capital Repairs Deduction	Line 3		$27,357,013	2034	4.461%	$3,976,080	$105,272,815
16	Less Bonus Depreciation	Line 13		$0	2035	4.462%	$3,976,971	$109,249,786
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$89,129,787	2036	4.461%	$3,976,080	$113,225,866
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	2037	4.462%	$3,976,971	$117,202,837
19	Remaining Tax Depreciation	Line 17 * Line 18		$3,342,367	2038	4.461%	$3,976,080	$121,178,916
					2039	4.462%	$3,976,971	$125,155,888
20	FY21 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$3,539,849	2040	4.461%	$3,976,080	$129,131,967
21	Cost of Removal	Page 13 of 29, Line 10		$11,093,804	2041	2.231%	$1,988,486	$131,120,453
						100.00%	$89,129,787	
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$45,333,033				

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investment

Line No.				(a) FY22
	Deferred Tax Subject to Proration			
1	Book Depreciation	Page 13 of 29, Line 16 + (Page 16 of 29, Line 19- Line 18)	$1,492,954	$2,985,908
2	Bonus Depreciation	Page 14 of 29, Line 13	$0	$0
3	Remaining MACRS Tax Depreciation	- Page 14 of 29, column (d) - (Page 16 of 29, Line 16- Line 15)	($3,342,367)	($6,434,279)
4	FY 2021 tax (gain)/loss on retirements	- Page 14 of 29, Line 20		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($1,849,413)	($3,448,371)
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($388,377)	($724,158)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 14 of 29, Line 3		
9	Cost of Removal	- Page 14 of 29, Line 21		
10	Book/Tax Depreciation Timing Difference at 3/31/2021			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	$0	$0
12	Effective Tax Rate		21.00%	21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13	($388,377)	($724,158)
15	Net Operating Loss	- Page 13 of 29, Line 21	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($388,377)	($724,158)
	Allocation of FY 2021 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($1,849,413)	($3,448,371)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($1,849,413)	($3,448,371)
20	Total FY 2021 Federal NOL (Utilization)	- Page 13 of 29, Line 21 / 21%	$0	$0
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$0	$0
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$0	$0
23	Effective Tax Rate		21%	21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$0	$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($388,377)	($724,158)

		(d) Number of Days in Month	(e) Proration Percentage	FY21	(f) FY22
	Proration Calculation				
26	April	30	91.78%	($29,705)	($55,387)
27	May	31	83.29%	($26,956)	($50,261)
28	June	30	75.07%	($24,296)	($45,301)
29	July	31	66.58%	($21,547)	($40,176)
30	August	31	58.08%	($18,798)	($35,051)
31	September	30	49.86%	($16,138)	($30,091)
32	October	31	41.37%	($13,389)	($24,965)
33	November	30	33.15%	($10,729)	($20,005)
34	December	31	24.66%	($7,980)	($14,880)
35	January	31	16.16%	($5,232)	($9,755)
36	February	28	8.49%	($2,749)	($5,125)
37	March	31	0.00%	$0	$0
38	Total	365		($177,518)	($330,996)
39	Deferred Tax Without Proration	Line 25		($388,377)	($724,158)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($194,188)	($362,079)
41	Proration Adjustment	Line 38 - Line 40		$16,670	$31,083

Column Notes:

(e) Sum of remaining days in the year (Col (d)) ÷ 365

(g) & (h) Current Year Line 25 ÷ 12 × Current Month Col (e)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
FY 2022 Revenue Requirement on FY 2021 Intangible Investment

Line No.		Reference	FY 21 (a)	FY 22 (b)
	Capital Investment			
1	Start of Rev. Req. Period		04/01/20	04/01/21
2	End of Rev. Req. Period		03/31/21	03/31/22
3	Investment Name		Volt-Var Optimization IS	Volt-Var Optimization IS
4	Work Order			
5	Total Spend	Section 2, Chart 10, Column 2 note	$0	$0
6	In ServiceDate	Estimated in-service date	09/30/20	09/30/20
7	Book AmortizationPeriod	Estimated useful life	84	84
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$0	$0
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$0	$0
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$0	$0
	Deferred Tax Calculation:			
11	Tax Amortizaton Period	Page 9 of 29	36	36
12	Tax Expensing	Per Tax Department	$0	$0
13	Tax Bonus Rate	Per Tax Department	0%	0%
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 0	$0	$0
15	Beginning Acc. Tax Balance	(L. 5 - L. 12- L.14)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%)	$0	$0
16	Ending Acc. Tax Balance	(L. 5 - L. 12- L.14) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$0	$0
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$0	$0
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$0	$0
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$0	$0
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$0	$0
21	Average Book / Tax Timer	Line 17 - Line 20	$0	$0
22	Effective Tax Rate		21%	21%
23	Deferred Tax Reserve	Line 21 × Line 22	$0	$0
	Rate Base Calculation:			
24	Average Book Balance	Line 10	$0	$0
25	Deferred Tax Reserve	Line 23	$0	$0
26	Average Rate Base	Line 24 - Line 25	$0	$0
	Revenue Requirement Calculation:			
27	Pre-Tax ROR	year 1 = Page 28 of 29, Line 27, column (e)×7÷12 Then = Page 28 of 29, Line 27(e)	8.23%	8.23%
28	Return and Taxes	Line 26 × Line 27	$0	$0
29	Book Depreciation	Line 9 - Line 8	$0	$0
30	Annual Revenue Requirement	Line 28 + Line 29	$0	$0

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
ISR Additions April 2020 through March 2021

Line No.	Month No.	Month	FY 2021 Plant Additions	In Rates	Not In Rates	Weight for Days	Weighted Average	Weight for Not in Rates
			(a)	(b)	(c) = (a) - (b)	(d)	(e) = (d) * (c)	(f)=(c)/Total(c)
1								
2	1	Apr-20	8,605,643	6,236,917	2,368,727	0.958	2,270,030	3.29%
3	2	May-20	8,605,643	6,236,917	2,368,727	0.875	2,072,636	3.29%
4	3	Jun-20	8,605,643	6,236,917	2,368,727	0.792	1,875,242	3.29%
5	4	Jul-20	8,605,643	6,236,917	2,368,727	0.708	1,677,848	3.29%
6	5	Aug-20	8,605,643	6,236,917	2,368,727	0.625	1,480,454	3.29%
7	6	Sep-20	8,605,643	-	8,605,643	0.542	4,661,390	11.94%
8	7	Oct-20	8,605,643	-	8,605,643	0.458	3,944,253	11.94%
9	8	Nov-20	8,605,643	-	8,605,643	0.375	3,227,116	11.94%
10	9	Dec-20	8,605,643	-	8,605,643	0.292	2,509,979	11.94%
11	10	Jan-21	8,605,643	-	8,605,643	0.208	1,792,842	11.94%
12	11	Feb-21	8,605,643	-	8,605,643	0.125	1,075,705	11.94%
13	12	Mar-21	8,605,643	-	8,605,643	0.042	358,568	11.94%
14		Total	$103,267,720	$31,184,583	$72,083,137		$26,946,065	100.00%
15	**Total September 2020 through March 2021**			**$**	**60,239,503**			
16	**FY2020 Weighted Average Incremental Rate Base Percentage**						**37.38%**	

Column (a)=Page 21 of 29, Line 1(c)
Column(b)=Page 21 of 29, Line 2(c)
Line 15 = sum of Line 7(c) through Line 13(c)
Line 16 = Line 14(f)/Line 14(c)

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2022 Revenue Requirement on FY 2022 Actual Incremental Capital Investment

Line No.				Fiscal Year 2022 (a)
	Capital Investment Allowance			
1	*Non-Discretionary Capital*	P 29 of 29. Line 1(a)		$46,562,272
	Discretionary Capital			
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	P 29 of 29. Line 3(a)		$42,200,430
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 21 of 29, Line 4(e)		$88,762,702
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$88,762,702
5	Retirements	Page 21 of 29 , Line 10 ,Col (e)		$34,853,004
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$53,909,698
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3		$88,762,702
8	Depreciation Expense	Page 25 of 29, Line 62, Col (d)		$49,906,920
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$38,855,782
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (e)		$7,658,876
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$46,514,657**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	Page 23 of 29, Line 3, Col (e)	1/	3.16%
13	Vintage Year Tax Depreciation:			
14	2022 Spend	Year 1 = Page 19 of 29, Line 21, Column (a), Then = Line Page 19 of 29 , Column (d)		$20,402,066
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$20,402,066
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$851,773
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$851,773
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$19,550,292
19	Effective Tax Rate			21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$4,105,561
21	Add: FY 2022 Federal (NOL) Utilization	Page 21 of 29, Line 15, Col (e)		$1,703,802
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21		$5,809,364
	Rate Base Calculation:			
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$46,514,657
24	Accumulated Depreciation	-Line 17		($851,773)
25	Deferred Tax Reserve	-Line 22		($5,809,364)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$39,853,520
	Revenue Requirement Calculation:			
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year, Line 26 * 50%; Then = (Prior Year Line 26 + Current Year Line 26) ÷ 2		$19,926,760
28	Proration Adjustment	Page 20 of 29, Line 41		$19,772
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29		$19,946,532
30	Pre-Tax ROR	Page 28 of 29, Line 33		8.23%
31	Return and Taxes	Line 29 * Line 30		$1,641,600
32	Book Depreciation	Line 16		$851,773
33	**Annual Revenue Requirement**	**Line 31 + Line 32**		**$2,493,373**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 23 of 29, Line 3, Col (e))

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2022 Incremental Capital Investments

Line No.				Fiscal Year 2022 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 18 of 29, Line 3		$88,762,702	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%				
					MACRS			
3	Capital Repairs Deduction	Line 1 * Line 2		$7,553,706	basis:	Line 16	$81,208,996	
							Annual	Cumulative
	Bonus Depreciation				Fiscal Year			
4	Plant Additions	Line 1		$88,762,702	2022	3.750%	$3,045,337	$20,402,066
5	Plant Additions			$0	2023	7.219%	$5,862,477	$26,264,543
6	Less Capital Repairs Deduction	Line 3		$7,553,706	2024	6.677%	$5,422,325	$31,686,868
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$81,208,996	2025	6.177%	$5,016,280	$36,703,147
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	2026	5.713%	$4,639,470	$41,342,617
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$0	2027	5.285%	$4,291,895	$45,634,513
10	Bonus Depreciation Rate	at 0%		0.00%	2028	4.888%	$3,969,496	$49,604,009
11	Total Bonus Depreciation Rate	Line 10		0.00%	2029	4.522%	$3,672,271	$53,276,279
12	Bonus Depreciation	Line 9 * Line 11		$0	2030	4.462%	$3,623,545	$56,899,825
					2031	4.461%	$3,622,733	$60,522,558
	Remaining Tax Depreciation				2032	4.462%	$3,623,545	$64,146,103
13	Plant Additions	Line 1		$88,762,702	2033	4.461%	$3,622,733	$67,768,837
14	Less Capital Repairs Deduction	Line 3		$7,553,706	2034	4.462%	$3,623,545	$71,392,382
15	Less Bonus Depreciation	Line 12		$0	2035	4.461%	$3,622,733	$75,015,115
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$81,208,996	2036	4.462%	$3,623,545	$78,638,661
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	2037	4.461%	$3,622,733	$82,261,394
18	Remaining Tax Depreciation	Line 16 * Line 17		$3,045,337	2038	4.462%	$3,623,545	$85,884,940
					2039	4.461%	$3,622,733	$89,507,673
19	FY22 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$2,144,147	2040	4.462%	$3,623,545	$93,131,218
20	Cost of Removal	Page 18 of 29, Line 10		$7,658,876	2041	4.461%	$3,622,733	$96,753,952
					2042	2.231%	$1,811,773	$98,565,724
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$20,402,066		100.00%	$81,208,996	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**			(a) FY22
1	Book Depreciation	Page 18 of 29, Line 16		$851,773
2	Bonus Depreciation	- Page 19 of 29, Line 12		$0
3	Remaining MACRS Tax Depreciation	- Page 19 of 29, column (d)		($3,045,337)
4	FY 2022 tax (gain)/loss on retirements	- Page 19 of 29, Line 19		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($2,193,564)
6	Effective Tax Rate			21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($460,648)
	Deferred Tax Not Subject to Proration			
8	Capital Repairs Deduction	- Page 19 of 29, Line 3		
9	Cost of Removal	- Page 19 of 29, Line 20		
10	Book/Tax Depreciation Timing Difference at 3/31/2022			
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		$0
12	Effective Tax Rate			21.00%
13	Deferred Tax Reserve	Line 11 * Line 12		$0
14	Total Deferred Tax Reserve	Line 7 + Line 13		($460,648)
15	Net Operating Loss	- Page 18 of 29, Line 21		$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($460,648)
	Allocation of FY 2022 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5		($2,193,564)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($2,193,564)
20	Total FY 2022 Federal NOL (Utilization)	- Page 18 of 29, Line 21 / 21%		$0
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20		$0
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20		$0
23	Effective Tax Rate			21%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23		$0
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($460,648)
		(d)	(e)	(f)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY23
26	April	30	91.78%	($35,232)
27	May	31	83.29%	($31,972)
28	June	30	75.07%	($28,817)
29	July	31	66.58%	($25,557)
30	August	31	58.08%	($22,296)
31	September	30	49.86%	($19,141)
32	October	31	41.37%	($15,881)
33	November	30	33.15%	($12,726)
34	December	31	24.66%	($9,465)
35	January	31	16.16%	($6,205)
36	February	28	8.49%	($3,260)
37	March	31	0.00%	$0
38	Total	365		($210,552)
39	Deferred Tax Without Proration	Line 25		($460,648)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($230,324)
41	Proration Adjustment	Line 38 - Line 40		$19,772

Column Notes:

(e) Sum of remaining days in the year (Col (d)) ÷ 365

(g) & (h) Current Year Line 25 ÷ 12 × Current Month Col (e)

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
FY 2018 - 2022 Incremental Capital Investment Summary

Line No.			Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)
	Capital Investment						
1	ISR - Eligible Capital Investment	Col (a) = FY 2018 ISR Docket No.4682, Att MAL-1 P2, L3; Col (b)=FY 2019 ISR Docket No.4783, Att PCE-1 P3, Table 1; Col (c)= Section I of Att. PCE-1, Table 2	$92,659,654	$111,243,061	$103,267,720	$116,486,800	$88,762,702
2	Intangible Assest included in Total Allowed Discretionary Capital	Col (a) =0; Col (b) = FY 2019 ISR Docket No. 4783, Att. MAL-1,Page 30 of 38, Line13; Col (c) = Actual per Operation	$0	$3,460,626	$0	$0	$0
3	ISR - Eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P5, L1, Col (a) = Col(a)+Col(b); Col(b)=Col(c)+Col(d); Col(c)=Col(e), Col(d)=Col(j)+Col(k)	$74,843,000	$74,843,000	$31,184,583	$0	$0
4	Incremental ISR Capital Investment (non-intangible)	Line 1 - Line 2 - Line 3	$17,816,654	$32,939,435	$72,083,137	$116,486,800	$88,762,702
	Cost of Removal						
5	ISR - Eligible Cost of Removal	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)= Section 1 of Att. PCE-1, Table 3	$9,979,698	$7,949,082	$14,387,482	$11,299,204	$7,744,459
6	ISR - Eligible Cost of Removal in Rate Base per RIPUC Docket No. 4770	Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L10×3÷12, [P1]L26+L45×7÷12; Col(b)=[P1]L45×5÷12+[P2]L18×7÷12; Col (c) = [P2]L18×5÷12+L39×7÷12	$8,259,707	$7,848,009	$3,437,925	$205,400	$85,583
7	Incremental Cost of Removal	Line 5 - Line 6	$1,719,991	$101,073	$10,949,557	$11,093,804	$7,658,876
	Retirements						
8	ISR - Eligible Retirements/Actual	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)=Per Company's Book	$15,206,748	$12,015,754	$13,944,441	$22,589,226	$35,100,171
9	ISR - Eligible Retirements in Rate Base per RIPUC Docket No. 4770	Schedule 6-ELEC, Docket No. 4770: Col(a)=Docket No. 4682, FY2018 ISR Elec Rec, [P2]L5×3÷12+[P1]L25+L27+L46×7÷12; Col(b)=[P1]L46×5÷12+[P2]L19×7÷12; Col (c)=[P2]L19×5÷12+L40×7÷12	$20,451,820	$22,665,233	$9,928,809	$593,200	$247,167
10	Incremental Retirements	Line 8 - Line 9	($5,245,072)	($10,649,479)	$4,015,632	$21,996,026	$34,853,004
	Net NOL Position						
11	ISR - (NOL)/Utilization	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2021 ISR Plan Docket No. 4995, Col (c)=Per Tax Departmen	($4,571,409)	$1,506,783	$0	$1,695,589	$8,772,838
12	less: (NOL)/Utilization recovered in transmission rates	Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 11	($1,572,911)	$515,161	$0	$570,357	$2,983,755
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 22 of 29, Line 12	($2,998,499)	$991,622	$0	$1,125,232	$5,789,083
14	(NOL)/Utilization in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P. 12: Col (c)= L39×7÷12	$0	$0	$1,462,980	$6,764,379	$4,085,281
15	Incremental (NOL)/Utilization	Line 13 - Line 14	($2,998,499)	$991,622	($1,462,980)	($5,639,147)	$1,703,802

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Electric ISR Revenue Requirement Reconciliation
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)		(d)	(e)	(f)	(g)	(h)
			Test Year July 2016 - June 2017					Jul & Aug 2017	12 Mths Aug 31 2018	12 Mths Aug 31 2019	12 Mths Aug 31 2020	12 Mths Aug 31 2021
1	Total Base Rate Plant DIT Provision		$18,265,666					$2,580,654	$5,847,765	$4,355,117	$707,056	$3,826,291
2	Excess DIT Amortization									($3,074,665)	($3,074,665)	($3,074,665)
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
3	Total Base Rate Plant DIT Provision							$10,558,267	$3,183,499	($847,583.55)	($548,055)	$313,177
4	Incremental FY 18	$4,261,399	$4,223,434	$4,181,310	$4,130,879	$4,072,741	$4,007,493	$4,261,399	($37,965)	($42,125)	($50,431)	($58,138)
5	Incremental FY 19	$0	$2,128,597	$2,305,665	$2,485,863	$2,504,666	$2,444,781		$2,128,597	$177,068	$180,198	$18,803
6	Incremental FY 20			$4,774,661	$5,289,496	$5,731,763	$6,107,088			$4,774,661	$514,834	$442,268
7	Incremental FY 21				$9,206,417	$9,930,574	$10,553,285				$9,206,417	$724,158
8	Incremental FY 22					$4,105,561	$4,978,937					$4,105,561
9	Incremental FY 23											
10	TOTAL Plant DIT Provision	$4,261,399	$6,352,031	$11,261,635	$21,112,654	$26,345,306	$28,091,583	$14,819,666	$5,274,131	$4,062,021	$9,302,963	$5,545,829
11	Distribution-related NOL							$2,998,499	($991,622)	$0	($1,125,232)	($5,789,083)
12	Lesser of Distribution-related NOL or DIT Provision							$2,998,499	($991,622)	$0	($1,125,232)	($5,789,083)
13	Total NOL											
14	NOL recovered in transmission rates											
15	Distribution-related NOL											

Line Notes:
1(b) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 2 of 23, Line 29, Col (e) - (a)
1(d) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 3
1(e) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 7
1(f) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 50
2 RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Sch. 11-ELEC, P.11 of 20, L. 51; P. 12 of 20, L. 42 & 52

3 Col(e) = Line 1(b)÷12×3+ Line1(d) + Line1(e)÷12×7; Col (f) = (Line1(e) + Line2(e))÷12×5 + (Line1(f) + Line2(f))÷12×7; Col (g) = (Line1(f) + Line2(f))÷12×5 + (Line1(g) + Line2(g))÷12×7
4(a)~(d) Cumulative DIT per vintage year ISR revenue requirement calculations (P.2, L.20(a)+L.22(a); P.2, L.20(b)+L.22(b); P.2, L.20(c)+L.22(c); P.2, L.20(d)+L.22(d))
5(b)~(d) Cumulative DIT per vintage year ISR revenue requirement calculations (P.5, L.20(a)+P.8, L.23(c); P.5, L.20(b)+P.8, L.23(f); P.5, L.20(c)+P.8, L.23(i))
6(c)~(d) Cumulative DIT per vintage year ISR revenue requirement calculations (P.10, L.20(a): P.10, L.20(b))
7(d) Cumulative DIT per vintage year ISR revenue requirement calculations (P.13, L.20(a)+P.15, L.23(a))
4(e) -7(g) Year over year change in cumulative DIT shown in Cols (a) through (d)
10 Sum of Lines 3 through 7
11 Page 21 of 29, Line 13
12 Lesser of Line 10 or Line 11
13 Per Tax Department
14 Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 13
15 Line 13 - Line 14

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-ELEC
Page 3 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

				Adjusted Plant Balance (a)	Approved Rate (b)	Test Year Depreciation (c) = (a) x (b)
			Intangible Plant			
1	303.00		Intangible Cap Software	($0)	0.00%	$0
2						
3			Total Intangible Plant	($0)		$0
4						
5			Production Plant			
6						
7	330.00		Land Hydro	$6,989	0.00%	$0
8	331.00		Struct & Improvements	$1,993,757	0.00%	$0
9	332.00		Reservoirs Dams And Water	$1,125,689	0.00%	$0
10						
11			Total Production Plant	$3,126,434		$0
12						
13			Total Transmission Plant	$0		$0
14						
15			Distribution Plant			
16						
17	360		Land & Land Rights New	$ -	0.00%	$ -
18	362		Station Equipment	$ -	2.32%	$ -
19	365		Overhead Conductors and Devices	$ -	3.02%	$ -
20	367.1		Underground Conductors and Devices	$ -	2.52%	$ -
21	360.00		Land & Land Rights New	$ 12,874,490	0.00%	$ -
22	360.10		Land Structures & Dist	$ 95,396	0.00%	$ -
23	361.00		Struct & Improvements	$ 10,144,741	1.36%	$ 137,968
24	362.00		Station Equipment	$ 253,879,227	2.19%	$ 5,559,955
25	362.10		Station Equip Pollution	$ 71,597	2.19%	$ 1,568
26	362.55		Station Equipment - Energy Management Syst	$ 663,280	6.70%	$ 44,440
27	364.00		Poles, Towers And Fixtures	$ 237,914,852	4.27%	$ 10,158,964
28	365.00		Oh Conduct-Smart Grid	$ 308,051,305	2.65%	$ 8,163,360
29	366.10		Underground Manholes A	$ 23,368,987	1.33%	$ 310,808
30	366.20		Underground Conduit	$ 48,513,051	1.55%	$ 751,952
31	367.10		Underground Conductors	$ 173,808,945	3.42%	$ 5,944,266
32	368.10		Line Transformers - Stations	$ 10,674,398	2.76%	$ 294,613
33	368.20		Line Transformers - Bare Cost	$ 101,452,162	3.14%	$ 3,180,525
34	368.30		Line Transformers - Install Cost	$ 77,701,753	3.22%	$ 2,501,996
35	369.10		Overhead Services	$ 83,166,615	5.04%	$ 4,191,597
36	369.20		Underground Services C	$ 1,691,919	4.87%	$ 82,396
37	369.21		Underground Services C	$ 22,150,773	4.87%	$ 1,078,743
38	370.10		Meters - Bare Cost - Domestic	$ 26,366,117	5.61%	$ 1,479,139
39	370.20		Meters - Install Cost - Domestic	$ 10,026,102	5.81%	$ 582,517
40	370.30		Meters - Bare Cost - Large	$ 11,492,790	5.69%	$ 653,940
41	370.35		Meters - Install Cost - Large	$ 9,186,534	5.13%	$ 471,269
42	371.00		Installation On Custom	$ 119,825	3.61%	$ 4,326
43	373.10		Oh Steetlighting	$ 23,671,126	1.46%	$ 345,598
44	373.20		Ug Streetlighting	$ 16,012,987	1.52%	$ 243,397
45	374.00	1/	Elect Equip ARO	$ -	0.00%	$ -
46						
47			Total Distribution Plant	$ 1,463,098,971	**3.16%**	$ 46,183,339
48						
49			General Plant			
50						
51	389.00		Land And Land Rights	$ 842,411	0.00%	$ -
52	390.00		Struct And Improvement Electric	$ 34,216,272	2.28%	$ 780,131
53	391.00		Office Furn &Fixt Electric (Fully Dep)	$ 30,645	0.00%	$ 29,542
54	391.00		Office Furn &Fixt Electric	$ 412,269	6.67%	$ 27,498
55	393.00		Stores Equipment	$ 93,412	5.00%	$ 4,671
56	394.00		General Plant Tools Shop	$ 1,934,730	5.00%	$ 96,736
57	395.00		General Plant Laboratory (Fully Dep)	$ 288,227	0.00%	$ -
58	395.00		General Plant Laboratory (Fully Dep)	$ 1,226,832	6.67%	$ 81,830
59	397.00		Communication Equipment	$ 5,337,629	5.00%	$ 266,881
60	397.10		Communication Equipment Site Specific	$ 2,530,920	3.90%	$ 98,706
61	397.50		Communication Equipment Network	$ 49,498	5.00%	$ 2,475
62	398.00		General Plant Miscellaneous	$ 706,169	6.67%	$ 47,101
63	399.00		Other Tangible Property	$ 12,484	0.00%	$ -
64	399.10	1/	ARO	$ (0)	0.00%	$ -
65						
66			Total General Plant	$ 47,681,498	**3.01%**	$ 1,435,572
67						
68			Grand Total - All Categories	$ 1,513,906,902	**3.15%**	$ 47,618,911

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Rate per RIPUC Docket No. 4995

		Adjusted Plant Balance (d)	Average Rate (e)=(f)/(d)	Approved Depreciation (f)
1	Total Distribution Plant	$ 1,463,098,971	3.16%	$ 46,183,339
2	Communication Equipment	$ 7,918,047	4.65%	$ 368,062
3	Total ISR eligible Plant	$ 1,471,017,018	**3.16%**	$ 46,551,401
4				
5	Non-ISR or Communication Plant	$ 42,889,885		
6	Grand Total - All Plant	$ 1,513,906,902		

Line Notes:
1 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on left Line 47
2 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on Left Lines 59 through 61
3 Line 1+Line 2
5 Docket No. 4770, Schedule 6-ELEC: [P3 and P4] on Left Lines 59 through 61
6 Line 3+Line 6
Column Notes:

(a) - (c) - Per Docket 4770/4780 Compliance Attachment 2, Schedule 6 ELEC, Pages 3 & 4

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-ELEC
Page 1 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Expense in Base Rates

Line No.	Description		Reference	Amount		less non-ISR eligible plant	ISR Eligible Amount
			(a)	(b)		(c)	(d)
1	Total Company Rate Year Distribution Depreciation Expense		Sum of Page 2, Line 16 and Line 17	$50,128,332	1		
2	Test Year Depreciation Expense		Per Company Books	$69,031,187	2		
3	Less : Test Year IFA related Depreciation Expense		Page 4, Line 30, Column (c)	($19,814,202)	3		
4	Less: ARO and other adjustments		Page 4, Line 30, Column (b) + Column (d)	($55,610)	4		
5	Adjusted Total Company Test Year Distribution Depreciation Expense		Sum of Line 2 through Line 4	$49,161,375	5		
6	Depreciation Expense Adjustment		Line 1 - Line 5	$966,957	6		
7					7		
8				Per Book	8		
9	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount	9		
10	Total Distribution Utility Plant 06/30/17		Page 4, Line 28, Column (e)	$2,141,474,644	10	($39,763,450)	$2,101,711,193
11	Less Non Depreciable Plant		Page 4, Line 26, Column (e)	($627,567,742)	11		($627,567,742)
12	Depreciable Utility Plant 6/30/17		Line 10 + Line 11	$1,513,906,902	12	($39,763,450)	$1,474,143,451
13					13		
14	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-ELEC, Page 6, Line 7	$12,473,833	14	$0	$12,473,833
15	Less: Streetlights retired in the 2 Mos Ended 08/31/17		Per Company Books	($1,057,011)	15	$0	($1,057,011)
16	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 14 x Retirement Rate	($3,699,739)	16	$0	($3,699,739)
17	Depreciable Utility Plant 08/31/17		Line 12 + Line 14 + Line 16	$1,521,623,985	17	($39,763,450)	$1,481,860,535
18					18		
19	Average Depreciable Plant from 06/30/17 to 08/31/17		(Line 12 + Line 17)/2	$1,517,765,443	19		$1,478,001,993
20					20		
21	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.40%	21		3.40%
22					22		
23	Book Depreciation Reserve 06/30/17		Page 5, Line 69, Column (e)	$652,405,159	23		
24	Plus: Book Depreciation Expense excluding Streetlight Retirement		1/6 of (Line 19 excl. Line 15 x Line 21)	$8,603,666	24		$8,381,334
25	Less: Streetlights retired in the 2 Mos Ended 08/31/17 and Dep. for 2 Mos		1/12 of (Line 15 x SL Dep Rate)	($1,307)	25		($1,307)
26	Less: Net Cost of Removal/(Salvage)	2/	Line 14 x Cost of Removal Rate	($1,281,063)	26		
27	Less: Retired Plant		Line 16	($3,699,739)	27		
28	Book Depreciation Reserve 08/31/17		Sum of Line 23 through Line 27	$656,026,715	28		
29					29		
30	Depreciation Expense 12 Months Ended 08/31/18				30		
31	Total Utility Plant 08/31/17		Line 10 + Line 14 + Line 15 + Line 16	$2,149,191,727	31	($39,763,450)	$2,109,428,277
32	Less Non Depreciable Plant		Line 11	($627,567,742)	32	$0	($627,567,742)
33	Depreciable Utility Plant 08/31/17		Line 31 + Line 32	$1,521,623,985	33	($39,763,450)	$1,481,860,535
34					34		
35	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-ELEC, Page 6, Line 14	$74,843,000	35	$0	$74,843,000
36	Less: Plant Retired in 12 Months Ended 08/31/18	1/	Line 35 x Retirement rate	($22,198,434)	36	$0	($22,198,434)
37	Depreciable Utility Plant 08/31/18		Sum of Line 33 through Line 36	$1,574,268,551	37	($39,763,450)	$1,534,505,101
38					38		
39	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 33 + Line 37)/2	$1,547,946,268	39	($39,763,450)	$1,508,182,818
40					40		
41	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.40%	41		3.40%
42					42		
43	Book Depreciation Reserve 08/31/17		Line 28	$656,026,715	43		
44	Plus: Book Depreciation 08/31/18		Line 39 x Line 41	$52,630,173	44		$51,278,216
45	Less: Net Cost of Removal/(Salvage)	2/	Line 35 x Cost of Removal Rate	($7,686,376)	45		
46	Less: Retired Plant		Line 36	($22,198,434)	46		
47	Book Depreciation Reserve 08/31/18		Sum of Line 43 through Line 46	$678,772,079	47		

1/ 3 year average retirement over plant addition in service FY 15 ~ FY17 29.66%
2/ 3 year average Cost of Removal over plant addition in service FY 15 ~ FY17 10.27%

Compliance Attachment 2
Schedule 6-ELEC
Page 2 of 5

The Narragansett Electric Company d/b/a National Grid
Depreciation Expense - Electric

For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Expense in Base Rates
(Continued)

Line No.		Description		Reference	Amount		less non-ISR eligible plant	ISR Eligible Amount
				(a)	(b)		(c)	(d)
1		**Rate Year Depreciation Expense 12 Months Ended 08/31/19:**				1		
2		Total Utility Plant 08/31/18		Page 1, Line 31 + Line 35 + Line 36	$2,201,836,293	2	($39,763,450)	$2,162,072,843
3		Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)	3	$0	($627,567,742)
4		Depreciable Utility Plant 08/31/18		Line 2 + Line 3	$1,574,268,551	4	($39,763,450)	$1,534,505,101
5						5		
6		Plus: Added Plant 12 Months Ended 08/31/19		Schedule 11-ELEC, Page 6, Line 38	$77,541,000	6	($2,698,000)	$74,843,000
7		Less: Depreciable Retired Plant	1/	Line 6 x Retirement rate	($22,998,661)	7	$800,227	($22,198,434)
8						8		
9		Depreciable Utility Plant 08/31/19		Sum of Line 4 through Line 7	$1,628,810,891	9	($41,661,224)	$1,587,149,667
10						10		
11		Average Depreciable Plant for Rate Year Ended 08/31/19		(Line 4 + Line 9)/2	$1,601,539,721	11	($40,712,337)	$1,560,827,384
12						12		
13		Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%	13		3.16%
14						14		
15		Book Depreciation Reserve 08/31/18		Page 1, Line 47	$678,772,079	15		
16		Plus: Book Depreciation Expense		Line 11 x Line 13	$50,375,341	16		$49,322,145
17		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)	17		($247,009)
18		Less: Net Cost of Removal/(Salvage)	2/	Line 6 x Cost of Removal Rate	($7,963,461)	18		
19		Less: Retired Plant		Line 7	($22,998,661)	19		
20		Book Depreciation Reserve 08/31/19		Sum of Line 15 through Line 19	$697,938,290	20		$49,075,136
21						21		
22		**Rate Year Depreciation Expense 12 Months Ended 08/31/20:**				22		
23		Total Utility Plant 08/31/19		Line 2 + Line 6 + Line 7	$2,256,378,633	23	($41,661,224)	$2,214,717,409
24		Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)	24	$0	($627,567,742)
25		Depreciable Utility Plant 08/31/19		Line 23 + Line 24	$1,628,810,891	25	($41,661,224)	$1,587,149,667
26						26		
27		Plus: Added Plant 12 Months Ended 08/31/20		Schedule 11-ELEC, Page 5, Line 15(i)	$2,000,000	27	($2,000,000)	$0
28		Less: Depreciable Retired Plant	1/	Line 27 x Retirement rate	($593,200)	28	$593,200	$0
29						29		
30		Depreciable Utility Plant 08/31/20		Sum of Line 25 through Line 28	$1,630,217,691	30	($43,068,024)	$1,587,149,667
31						31		
32		Average Depreciable Plant for Rate Year Ended 08/31/20		(Line 25 + Line 30)/2	$1,629,514,291	32	($42,364,624)	$1,587,149,667
33						33		
34		Proposed Composite Rate %		Page 4, Line 18, Column (f)	3.15%	34		3.16%
35						35		
36		Book Depreciation Reserve 08/31/20		Line 20	$697,938,290	36		
37		Plus: Book Depreciation Expense		Line 32 x Line 34	$51,255,262	37		$50,153,929
38		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)	38		($247,009)
39		Less: Net Cost of Removal/(Salvage)	2/	Line 27 x Cost of Removal Rate	($205,400)	39		
40		Less: Retired Plant		Line 28	($593,200)	40	7 mos FY20	12 mos
41		Book Depreciation Reserve 08/31/20		Sum of Line 36 through Line 40	$748,147,943	41	$ 436,419,633	$49,906,920
42						42		
43		**Rate Year Depreciation Expense 12 Months Ended 08/31/21:**				43		
44		Total Utility Plant 08/31/20		Line 23 + Line 27 + Line 28	$2,257,785,433	44	($43,068,024)	$2,214,717,409
45		Less Non-Depreciable Plant		Page 1, Line 11	($627,567,742)	45	$0	($627,567,742)
46		Depreciable Utility Plant 08/31/20		Line 44 + Line 45	$1,630,217,691	46	($43,068,024)	$1,587,149,667
47						47		
48		Plus: Added Plant 12 Months Ended 08/31/21		Schedule 11-ELEC, Page 5, Line 15(l)	$2,000,000	48	($2,000,000)	$0
49		Less: Depreciable Retired Plant	1/	Line 48 x Retirement rate	($593,200)	49	$593,200	$0
50						50		
51		Depreciable Utility Plant 08/31/21		Sum of Line 46 through Line 49	$1,631,624,491	51	($44,474,824)	$1,587,149,667
52						52		
53		Average Depreciable Plant for Rate Year Ended 08/31/21		(Line 46 + Line 51)/2	$1,630,921,091	53	($43,771,424)	$1,587,149,667
54						54		
55		Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%	55		3.16%
56						56		
57		Book Depreciation Reserve 08/31/20		Line 41	$748,147,943	57		
58		Plus: Book Depreciation Expense		Line 53 x Line 55	$51,299,512	58		$50,153,929
59		Plus: Unrecovered Reserve Adjustment		Schedule NWA-1-ELECTRIC, Part VI, Page 6	($247,009)	59		($247,009)
60		Less: Net Cost of Removal/(Salvage)	2/	Line 48 x Cost of Removal Rate	($205,400)	60		
61		Less: Retired Plant		Line 49	($593,200)	61		
62		Book Depreciation Reserve 08/31/21		Sum of Line 57 through Line 61	$798,401,846	62		$49,906,920
63								
64	1/	3 year average retirement over plant addition in service FY 15 ~ FY17		29.66%	Retirements			
65	2/	3 year average Cost of Removal over plant addition in service FY 15 ~ FY17		10.27%	COR			
66								
67		Book Depreciation RY2		Line 37 (a) + Line 38 (b)				$51,008,253
68		Less: General Plant Depreciation (assuming add=retirement)		- Page 23 of 29, Line 66 (c)				($1,435,572)
69		Plus: Comm Equipment Depreciation		Page 23 of 29, sum of Lines 59 (c) through 61 (c)				$368,062
70		Total						$49,940,743
71		7 Months						x7/12
72		FY 2020 Depreciation Expense		Line 66 (d) ×7 ÷12				$29,132,100
73								
74		Book Depreciation RY3		Line 58 (a) + Line 59 (b)				$51,052,503
75		Less: General Plant Depreciation		- Page 23 of 29, Line 66 (c)				($1,435,572)
76		Plus: Comm Equipment Depreciation		Page 23 of 29, sum of Lines 59 (c) through 61 (c)				$368,062
77		Total						$49,984,993
78		FY 2021 Depreciation Expense		Line 66 (d) ×5 ÷12 + Line 73 (d) ×7 ÷12				$49,966,556

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 ISR Property Tax Recovery Adjustment 1
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	End of FY 2018	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2019
1	Plant In Service	$1,595,499	$111,243	$3,137	$114,380		($12,016)		$1,697,863
2	Accumulated Depr	$672,116				$52,896	($12,016)	($7,949)	$705,047
3	Net Plant	$923,383							$992,816
4	Property Tax Expense	$30,354							$32,077
5	Effective Prop Tax Rate	3.29%							3.23%
	Effective tax Rate Calculation	End of FY 2019	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2020
6	Plant In Service	$1,697,863	$103,268	$4,244	$107,511		($14,649)		$1,790,725
7	Accumulated Depr	$705,047				$54,318	($14,649)	($14,387)	$730,328
8	Net Plant	$992,816							$1,060,397
9	Property Tax Expense	$32,077							$32,568
10	Effective Prop Tax Rate	3.23%							3.07%
	Effective Tax Rate Calculation	End of FY 2020	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2021
11	Plant In Service	$1,790,725	$116,487	$2,024	$118,510		($22,589)		$1,886,646
12	Accumulated Depr	$730,328				$57,246	($22,589)	($11,299)	$753,685
13	Net Plant	$1,060,397							$1,132,961
14	Property Tax Expense	$32,568							$33,333
15	Effective Prop Tax Rate	3.07%							2.94%
	Effective Tax Rate Calculation	End of FY 2021	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2022
16	Plant In Service	$1,886,646	$88,763	$13,092	$101,855		($35,100)		$1,953,401
17	Accumulated Depr	$753,685				$59,937	($35,100)	($7,744)	$770,777
18	Net Plant	$1,132,961							$1,182,624
19	Property Tax Expense	$33,333							$33,955
20	Effective Prop Tax Rate	2.94%							2.87%

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 ISR Property Tax Recovery Adjustment 2 (continued)
(000s)

	Property Tax Recovery Calculation	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Cumulative Increm. ISR Prop. Tax for FY2018			Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 months			Cumulative Increm. ISR Prop. Tax for FY2019 7 months		
21	Incremental ISR Additions		$92,660			$111,243			$36,400	
22	Book Depreciation: base allowance on ISR eligible plant		($43,032)			($43,032)			$0	
23	Book Depreciation: current year ISR additions		($1,317)			($1,628)			($999)	
24	COR		$9,980			$7,949			$101	
25	Net Plant Additions		$58,291			$74,532			$35,502	
26	RY Effective Tax Rate		3.98%			3.98%			3.28%	
									1.91%	
27	ISR Year Effective Tax Rate	3.29%			3.23%					
28	RY Effective Tax Rate	3.98%	-0.69%		3.98%	-0.75%		3.23%		
29	RY Effective Tax Rate 5 mos for FY 2019		-0.69%		5 month	-0.31%		3.28%	-0.05%	
30	RY Net Plant times 5 mo rate	$746,900	-0.69%	($5,191)	$746,900	-0.31%	($2,338)		-0.03% 7 mos	
31	FY 2014 Net Adds times ISR Year Effective Tax rate	$1,566	3.29%	$51	$1,232	1.35%	$17	$930,873	-0.03%	($279)
32	FY 2015 Net Adds times ISR Year Effective Tax rate	$34,308	3.29%	$1,128	$32,324	1.35%	$435			
33	FY 2016 Net Adds times ISR Year Effective Tax rate	$33,535	3.29%	$1,102	$32,090	1.35%	$432	$18,393	1.88%	$346
34	FY 2017 Net Adds times ISR Year Effective Tax rate	$38,200	3.29%	$1,256	$37,040	1.35%	$499	$35,502	1.88%	$669
35	FY 2018 Net Adds times ISR Year Effective Tax rate	$58,291	3.29%	$1,916	$55,850	1.35%	$752			
36	FY 2019 Net Adds times ISR Year Effective Tax rate				$74,532	1.35%	$1,003			
37	Total ISR Property Tax Recovery			$263			$800			$736

		(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
		Cumulative Increm. ISR Prop. Tax for FY2020			Cumulative Increm. ISR Prop. Tax for FY2021			Cumulative Increm. ISR Prop. Tax for FY2022		
38	Incremental ISR Additions		$72,083			$116,487			$88,763	
39	Book Depreciation: base allowance on ISR eligible plant		$0			$0			($29,112)	
40	Book Depreciation: current year ISR additions		($1,075)			($1,493)			($852)	
41	COR		$10,950			$11,094			$7,659	
42	Net Plant Additions		$81,957			$126,088			$66,457	
43	RY Effective Tax Rate		3.38%			3.58%			3.66%	
44	ISR Property Tax Recovery on non-ISR									
45	ISR Year Effective Tax Rate	3.07%			2.94%			2.87%		
46	RY Effective Tax Rate	3.38%	-0.31%		3.58%	-0.63%		3.66%	-0.79%	
47	RY Effective Tax Rate 7 mos for FY 2019									
48	RY Net Plant times Rate Difference	$902,404	-0.31%	($2,816)	$853,576	* -0.63%	($5,418)	$833,223	* -0.79%	($6,607)
49	Non-ISR plant times rate difference	($2,269)	-0.31%	$7	($4,269)	* -0.63%	$27	($6,269)	* -0.79%	$50
50	FY 2018 Net Incremental times rate difference	$17,664	3.07%	$543	$16,935	* 2.94%	$498	$16,207	* 2.87%	$465
51	FY 2019 Net Incremental times rate difference	$33,630	3.07%	$1,033	$31,759	* 2.94%	$934	$29,887	* 2.87%	$858
52	FY 2020 Net Incremental times rate difference	$81,957	3.07%	$2,517	$79,806	* 2.94%	$2,348	$77,655	* 2.87%	$2,229
53	FY 2021 Net Incremental times rate difference				$126,088	* 2.94%	$3,709	$123,102	* 2.87%	$3,534
54	FY 2022 Net Adds times rate difference							$66,457	* 2.87%	$1,908
55	Total ISR Property Tax Recovery			$1,284			$2,099			$2,437

Line Notes

1(a) - 15(h)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 20,
16(a) - 20(a)	=11(h) - 15(h)
16(b) - 16(d)	Docket No. 5098 Attachment 1C, Page 26 of 29, 16(b) to 16(d)
16(e)	Docket 5098, C. Att. 2, Sch 6-ELEC, P2: (L37(b) + L38(b)) +((, L 6(a) + , L 6(a)+, L(a)+, L6(a)) × 0.0316+29(d)+, L29(b))/1000 + (L1(c)+L6(c)+L11(c))×0.0301+, L6(a) × 0.0316× 0.5)/1000+L16(c)×0.5×0.0301
16(f) - 17(g)	Docket No. 5098 Attachment 1C, Page 26 of 29, 16(f) to 17(g)
16(h)	Sum of Lines 16(a) through 16(g)
17(h)	Sum of Lines 17(a) through 17(g)
18(h)	=16(h)-17(h)
19(h)	Per Company's Book
20(h)	Line 19(h) ÷ 18(h)

Line Notes

21(a) - 37(i)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
38(j) - 55(o)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
38(q) - 52(r)	Docket No. 5098 Attachment 1C, Page 26 of 29, 38(j) to 50(k)
53(p)	=53(m) - (Page 13 of 29, Line 16(b) ÷ 1000
54(p)	=42(q)
53(q) - 54(q)	=45(p)
53(r) - 54(r)	=53(p) to 54(p) x 53(q) to 54(q)
55(r)	Sum of Lines 48(r) through 54(r)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Electric Infrastructure, Safety, and Reliability (ISR) Plan
Calculation of Weighted Average Cost of Capital

Line No.		(a)	(b)	(c)	(d)	(e)
1	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 35% income tax rate effective April 1, 2013					
2		Ratio	Rate	Weighted Rate	Taxes	Return
3	Long Term Debt	49.95%	4.96%	2.48%		2.48%
4	Short Term Debt	0.76%	0.79%	0.01%		0.01%
5	Preferred Stock	0.15%	4.50%	0.01%		0.01%
6	Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
7		100.00%		7.17%	2.51%	9.68%
8						
9	(d) - Column (c) x 35% divided by (1 - 35%)					
10						
11	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4323 at 21% income tax rate effective January 1, 2018					
12		Ratio	Rate	Weighted Rate	Taxes	Return
13	Long Term Debt	49.95%	4.96%	2.48%		2.48%
14	Short Term Debt	0.76%	0.79%	0.01%		0.01%
15	Preferred Stock	0.15%	4.50%	0.01%		0.01%
16	Common Equity	49.14%	9.50%	4.67%	1.24%	5.91%
17		100.00%		7.17%	1.24%	8.41%
18						
19	(d) - Column (c) x 21% divided by (1 - 21%)					
20						
21	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
22		Ratio	Rate	Weighted Rate	Taxes	Return
23	Long Term Debt	48.35%	4.62%	2.23%		2.23%
24	Short Term Debt	0.60%	1.76%	0.01%		0.01%
25	Preferred Stock	0.10%	4.50%	0.00%		0.00%
26	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
27		100.00%		6.97%	1.26%	8.23%
28						
29	(d) - Column (c) x 21% divided by (1 - 21%)					
30						
31	FY18 Blended Rate		Line 7(e) x 75% + Line 17(e) x 25%			9.36%
32						
33	FY19 Blended Rate		Line 17 x 5 ÷ 12 + Line 27 x 7 ÷ 12			8.31%
34						
35	FY20 and after Rate			Line 27(e)		8.23%

The Narragansett Electric Company
d/b/a Rhode Island Energy
FY 2022 Incremental Capital Investment

Line No.			Fiscal Year 2022 (a)	In Base Rates Included In Docket No. 4770 (b)	Amount to be Included in FY 2021 ISR (c) = (a) - (b)
	Non Discretionary Capital				
1	FY 2022 Proposed Non-Discretionary Capital Additions	Column (a) Table 1, Col 2, Column (b) - Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (k).	**$46,562,272**	**$0**	$46,562,272
	Discretionary Capital				
2	Cumulative FY 2021 Discretionary Capital ADDITIONS	Docket 4915 + Docket 4995	$470,920,921		
3	FY 2022 Discretionary Capital ADDITIONS	Table 1, Col 2	$42,200,430		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$513,121,351		
5	Cumulative FY 2021 Discretionary Capital SPENDING	Docket 4915 + Docket 4995	$498,781,440		
6	FY 2022 Discretionary Capital SPENDING	Section 2, Chart 19, Col 1	$52,194,593		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$550,976,033		
8	Cumulative FY 2021 Approved Discretionary Capital SPENDING	Docket 4915 + Docket 4995	$490,326,536		
9	FY 2022 Approved Discretionary Capital SPENDING	Section 2, Chart 19, Col 1	$62,165,000		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$552,491,536		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$513,121,351		
12	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base	Docket No. 4915 -ISR Plan Reconciliation	$470,920,921		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$42,200,430**	**$0**	**$42,200,430**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$88,762,702**	**$0**	**$88,762,702**
15	Intangible Assets included in Total Allowed Discretionary Capital	Section 2, Chart 10, Column 2 note			$0
16	**Total Allowed Discretionary Capital Included in non-Intangible Rate Base Current Year**	Line 14 - Line 15			**$88,762,702**

PRE-FILED DIRECT TESTIMONY

OF

PETER R. BLAZUNAS

August 1, 2022

Table of Contents

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Peter R. Blazunas and my business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Please state your position.

A. I am a Project Manager for Concentric Energy Advisors, Inc. ("Concentric"), a management consulting firm. I am testifying on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company").

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Economics from the University of Dayton in 2009 and a Master of Arts degree in Economics from the University of Akron in 2011.

Q. Please describe your professional background.

A. I began my career with FirstEnergy Corp. in 2012 as a State Regulatory Analyst in the Ohio Rates and Regulatory Affairs Department. In July 2017, I joined the Potomac Electric Power Company ("Pepco") Regulatory Strategy and Revenue Policy team of the Regulatory Affairs Department of Pepco Holdings Inc. (PHI) as a Senior Rate Analyst. In November 2018, I assumed the position of Manager of Rate Administration for Pepco. In that role, I was responsible for the development of electric rates, including tariff surcharges, for Pepco's Maryland and District of Columbia jurisdictions, and also participated in the development of Pepco's policies and practices with respect to rate design and assisted with regulatory compliance matters, including tariff administration and periodic filings. I left Pepco in January 2021 and assumed my current role at Concentric in October 2021.

Q. Have you testified previously before the Rhode Island Public Utilities Commission ("PUC")?

A. Yes. I have submitted pre-filed testimony before the PUC in support of the Company's Renewable Energy (RE) Growth Program Factor filing in Docket No. 22-04-REG and the Company's Gas Revenue Decoupling Mechanism (RDM) Reconciliation filing in Docket No. 22-13-NG.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. My testimony presents the proposed CapEx and O&M Reconciling Factors, as those terms are defined in the Company's Infrastructure, Safety, and Reliability Provision, R.I.P.U.C. No. 2199 effective September 1, 2018 ("ISR Provision"), resulting from the reconciliation of actual costs and revenue associated with the Fiscal Year ("FY") 2022 ISR Plan ("ISR Plan" or "Plan"). In support of the proposed factors, my testimony presents the following:

- the results of the annual reconciliation of the actual FY 2022 capital investment ("CapEx") revenue requirement and the Operation and Maintenance ("O&M") expense to the actual revenue billed;
- the final status of the recovery of the FY 2020 CapEx and O&M reconciliations;
- the status of the credit of the FY 2021 CapEx and O&M reconciliations;
- the calculation of the proposed CapEx and O&M Reconciling Factors for effect October 1, 2022; and
- the typical bill impacts related to the proposed reconciling factors.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section III presents the Summary of FY 2022 CapEx and O&M Reconciliations;
- Section IV presents the results of the FY 2022 CapEx Revenue and the Actual CapEx Revenue Requirement Reconciliation, the calculation of the proposed CapEx Reconciling Factors, and the final status of the recovery from customers of the FY 2020 CapEx net under-recovery reconciliation balance as well as the status of the credit to customers of the FY 2021 CapEx net over-recovery reconciliation balance;
- Section V presents the results of the FY 2022 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the final status of the recovery from customers of the FY 2020 O&M under-recovery reconciliation balance as well as the status of the credit to customers of the FY 2021

O&M over-recovery reconciliation balance; and

- Section VI presents the rate class bill impact analysis.

III. Summary of FY 2022 Capex and O&M Reconciliations

Q. Please summarize the results of the FY 2022 CapEx and O&M reconciliations.

A. A summary of the results of the FY 2022 CapEx and O&M reconciliations is presented in Attachment PRB-1. Pursuant to the ISR Provision, the annual reconciliations compare the actual revenue billed during the Plan year through the approved CapEx and O&M Factors to the CapEx and O&M revenue requirement based on actual costs incurred. The calculation of the revenue requirement is presented in the testimony of Company Witnesses Stephanie A. Briggs and Jeffrey D. Oliveira. As reflected in Attachment PRB-1, the result of the CapEx reconciliation is a net over-recovery of approximately $4.5 million; the result of the O&M reconciliation is a net over-recovery of approximately $0.1 million.

Q. Please briefly summarize the operation of the tariff provision that enables the Company to recover certain costs through the ISR Plan.

A. In accordance with the ISR Provision, the Company is allowed to recover the revenue requirement related to capital investments through CapEx Factors and to recover certain expenditures for Inspection and Maintenance ("I&M") and Vegetation Management ("VM") activities through O&M Factors. In the ISR Plan filing for the upcoming year, the Company determines the CapEx Factors, which are designed to recover the revenue requirement on the forecasted capital investment for the ISR Plan's investment year plus cumulative capital investment in prior years' ISR Plans, as well as the O&M Factors based on the forecasted O&M expense for the Plan year. On an annual basis, the Company is required to reconcile the annual CapEx revenue requirement on actual cumulative ISR capital investment and the actual O&M expense incurred to actual billed revenue generated from the CapEx Factors and the O&M Factors, respectively. The over or under-recovered balances resulting from the CapEx and O&M reconciliations are either credited to or recovered from customers through the CapEx Reconciling Factors and the O&M Reconciling Factor, respectively.

IV. <u>Capex Reconciliation and Proposed Capex Reconciling Factors</u>

Q. What is the result of the CapEx reconciliation for FY 2022?

A. The FY 2022 CapEx reconciliation by rate class is presented in Attachment PRB-2, page 1. Line (4) reflects the CapEx revenue requirement on actual cumulative ISR capital investment of approximately $25.7 million. Line (5) represents the CapEx revenue billed during the period April 1, 2021 through March 31, 2022 of approximately $30.2 million. Line (6) identifies the net over-recovery by rate class of the CapEx revenue requirement, which totals approximately $4.5 million.

Q. Why has the Company prepared the CapEx reconciliation by rate class?

A. The ISR Provision requires that the CapEx Reconciling Factors be calculated as class-specific per-kWh factors designed to recover or credit the under- or over-recovery of the actual Cumulative Revenue Requirement, as allocated to each rate class by the Rate Base Allocator, for the prior fiscal year. The Rate Base Allocator is the percentage of total rate base allocated to each rate class determined in the most recently approved allocated cost of service study. Page 1, Line (4) of Attachment PRB-2 shows the allocation of the CapEx revenue requirement to each rate class based upon the Rate Base Allocator approved in the Company's 2017 general rate case in Docket No. 4770.

Q. Please describe the results of the rate class reconciliation.

A. As shown in Attachment PRB-2, page 1, the allocated FY 2022 revenue requirement on actual cumulative capital investment (Line (4)) is subtracted from the CapEx Factor revenue billed for each rate class (Line (5)), resulting in the net over-recovery of approximately $4.5 million (Line (6)). The detail of the CapEx revenue billed for each rate class is provided in Attachment PRB-2, page 2.

Q. Please describe the amounts included on Line (7) of Attachment PRB-2, Page 1.

A. The amounts presented on Page 1, Line (7) reflect the final balance of the net under-recovery resulting from the FY 2020 CapEx reconciliation. The net recovery of the FY 2020 CapEx reconciliation balance is presented on page 3. Of the $4.6 million net under-recovery for FY 2020 to be recovered from customers via CapEx Reconciling Factors approved by the PUC, the Company recovered $4.8 million from October 1, 2020 through September 30, 2021. The remaining balance is a net over-recovery amount of approximately $0.3 million, as shown on Attachment PRB-2, Page 1, Line (7), Column (a). As described in Docket No. 4682, the Company is including each rate class's residual balance associated with the FY 2020 reconciliation as an adjustment to the FY 2022 CapEx reconciliation balance.

Q. How is the Company proposing to credit the FY 2022 CapEx net over-recovery?

A. The Company is proposing to implement a CapEx Reconciling Factor for each rate class that is consistent with the results of the rate class reconciliation. The calculation of the proposed CapEx Reconciling Factors is presented in Attachment PRB-2, page 1. The over or under-recovery by rate class on Line (8) is divided by each rate class's forecasted kWh deliveries for the period October 1, 2022 through September 30, 2023 on Line (9). The class-specific CapEx Reconciling Factors are shown on Line (10).

Q. Is the Company providing the status of the net over-recovery from the FY 2021 CapEx reconciliation?

A. Yes. The status of the FY 2021 CapEx reconciliation net over-recovery balance is presented in Attachment PRB-2, page 4. As of June 30, 2022, the balance reflects a remaining net over-recovery of approximately $0.8 million, which the Company will continue to credit to customers through September 30, 2022.

Q. How will the Company propose to credit or recover any residual balances as of September 30, 2022?

A. Pursuant to the ISR Provision, the amount approved for recovery or refund through the CapEx Reconciling Factors is subject to reconciliation. Therefore, the Company will present the final reconciliation of balances from the FY 2021 CapEx reconciliation in the FY 2023 ISR Plan Reconciliation Filing and include each rate class's residual balance from the FY 2021 CapEx reconciliation with the balances resulting from the FY 2023 CapEx reconciliation and will propose CapEx Reconciling Factors on the total.

V. O&M Reconciliation and Proposed O&M Reconciling Factor

Q. What is the result of the O&M reconciliation for FY 2022?

A. The O&M reconciliation for FY 2022 is presented in Attachment PRB-3, page 1. Line (1) shows the actual O&M expense for FY 2022 of approximately $12.1 million, which is supported in the testimony of Company Witnesses Stephanie A. Briggs and Jeffrey D. Oliveira. Line (2) shows O&M revenue billed through the O&M Factors from April 1, 2021 through March 31, 2022 of approximately $12.2 million. Line (3) shows the difference of approximately $0.1 million, representing an over-recovery of actual O&M expense.

Q. Please describe the amount included on Line (4).

A. The amount presented on Line (4) reflects the remaining balance of the under-recovery resulting from the FY 2020 O&M reconciliation. The recovery from customers of the under-recovery balance is presented on page 3. Of the $172,390 under-recovery that formed the basis for the O&M Reconciling Factor approved by the PUC, the Company recovered from customers $145,890 from October 1, 2020 through September 30, 2021, leaving $26,500 remaining to be recovered from customers. As described in Docket No. 4682, the Company is including the residual balance as an adjustment to the FY 2022 O&M reconciliation balance.

Q. Is the Company providing the O&M Factor revenue?

A. Yes. Attachment PRB-3, page 2 presents the O&M Factor revenue billed by month.

Q. What is the proposed O&M Reconciling Factor?

A. The proposed O&M Reconciling Factor is calculated on Attachment PRB-3, page 1. The total amount to be credited to customers of $69,828 on Line (5) is divided by the forecasted kWh during the period October 1, 2022 through September 30, 2023, on Line (6). This amount, however, is too small to generate a billable factor. Consequently, the Company proposes to carry this over-recovery amount forward into the Company's next annual ISR filing for the reconciliation period October 2022 through September 2023.

Q. Is the Company providing the status of the over-recovery of the FY 2021 O&M reconciliation?

A. Yes. The status of the over-recovery balance from the FY 2021 O&M reconciliation is presented in Attachment PRB-3, page 4. As of June 30, 2022, there is a remaining over-recovery balance of approximately $0.3 million, which the Company will continue to credit to customers through September 30, 2022.

Q. How does the Company propose to credit or recover the residual balance at September 30, 2022?

A. Pursuant to the ISR Provision, the amount approved for recovery or crediting through the O&M Reconciling Factor is subject to reconciliation. Therefore, the Company will present the final reconciliation of the balance from the FY 2021 O&M reconciliation in the FY 2023 ISR Reconciliation Filing and include the residual balance of the FY 2021 O&M reconciliation with the results of the FY 2023 O&M reconciliation and will propose an O&M Reconciling Factor on the total.

VI. <u>Typical Bill Analysis</u>

Q. Is the Company providing a typical bill analysis to illustrate the impact of the proposed rates on each of the Company's rate classes?

A. Yes. The typical bill analysis illustrating the monthly bill impact of the proposed rate changes for each rate class is provided in Attachment PRB-4. The impact of the proposed CapEx Reconciling Factor of ($0.00089) per kWh and the proposed O&M Reconciling Factor of $0.00000 per kWh on a typical residential customer receiving Last Resort Service and using 500 kWh per month is a decrease of $0.06, or approximately 0.1%, from $111.15 to $111.09.

VII. Summary of Retail Delivery Rates

Q. Is the Company providing a proposed Summary of Retail Delivery Rates, R.I.P.U.C. No. 2095, reflecting the reconciling factors proposed in this filing?

A. No, not at this time. On August 1, 2022, concurrent with this filing, the Company will be submitting its Pension and Post-retirement Benefits Other than Pension Adjustment Factor ("PAF") filing in which the Company will propose a PAF, also for effect October 1, 2022. The Company has also submitted a Renewable Energy ("RE") Growth Factor Filing with factors also proposed for effect October 1, 2022. The Company will file a Summary of Retail Delivery Rates tariff reflecting all rates for effect October 1, 2022 in compliance with the PUC's orders in this proceeding and the PAF and the RE Growth proceedings.

VIII. Conclusion

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Attachment PRB-1

FY 2022 ISR Plan Annual Reconciliation Summary

FY 2022 ISR Plan Annual Reconciliation Summary

		CapEx	O&M	Total
		(a)	(b)	(c)
(1)	Actual Revenue Requirement	$25,679,615	$12,081,003	$37,760,618
(2)	Revenue Billed	$30,189,032	$12,177,331	$42,366,363
(3)	Total Over/(Under) Recovery	$4,509,417	$96,328	$4,605,745

(1) Column (a): Attachment SAB/JDO-1, Page 1, Line (12), Column (b)
Column (b): Attachment SAB/JDO-1, Page 1, Line (4), Column (b)
(2) Column (a): Attachment PRB-2, page 1, Line (5)
Column (b): Attachment PRB-3, page 1, line (2)
(3) Line (2) - Line (1)

(c) Sum of Columns (a) and (b)

Attachment PRB-2

CapEx Reconciliations and Proposed CapEx Reconciling Factors

Proposed CapEx Reconciling Factors
For Fiscal Year 2022 ISR Plan
For the Recovery/(Refund) Period October 1, 2022 through September 30, 2023

		Total (a)	Residential A-16 / A-60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	Lighting S-05/S-06 S-10/S-14 (f)	Propulsion X-01 (g)
(1)	Actual FY2022 Capital Investment Revenue Requirement	$25,679,615						
(2)	Total Rate Base ($000s)	$729,512	$404,995	$75,009	$117,155	$123,849	$8,296	$208
(3)	Rate Base as Percentage of Total	100.00%	55.52%	10.28%	16.06%	16.98%	1.14%	0.03%
(4)	Allocated Actual FY2022 Capital Investment Revenue Requirement	$25,679,615	$14,256,264	$2,640,398	$4,123,983	$4,359,619	$292,028	$7,322
(5)	CapEx Revenue Billed	$30,189,032	$16,902,285	$2,640,618	$5,026,403	$5,355,531	$253,958	$10,237
(6)	Total Over/(Under) Recovery for FY 2022	$4,509,417	$2,646,021	$220	$902,420	$995,912	($38,070)	$2,915
(7)	Remaining Over/(Under) For FY 2020	$270,343	$191,848	$48,737	($7,203)	$15,896	$21,692	($627)
(8)	Total Over/(Under) Recovery	$4,779,760	$2,837,869	$48,957	$895,217	$1,011,808	($16,378)	$2,288
(9)	Forecasted kWhs - October 1, 2022 through September 30, 2023	7,399,766,076	3,186,604,239	697,866,366	1,232,713,378	2,226,399,474	40,530,906	15,651,713
(10)	Proposed Class-specific CapEx Reconciling Factor Charge/(Credit) per kWh		($0.00089)	($0.00007)	($0.00072)	($0.00045)	$0.00040	($0.00014)

(1) per Attachment SAB/JDO-1, Page 1, Line (12), Column (b)
(2) per R.I.P.U.C. Docket No. 4770/4780, Compliance Attachment 6, (Schedule 1A), Page 1, Line 9
(3) Line (2) ÷ Line (2), Column (a)
(4) Line (1) x Line (3)
(5) per Page 2
(6) Line (5) - Line (4)
(7) per Page 3
(8) Line (6) + Line (7)
(9) per Company forecast
(10) -1 x (Line (8) ÷ Line (9)), truncated to 5 decimal places

Fiscal Year 2022 CapEx Reconciliation
For the Period April 1, 2021 through March 31, 2022
For the Recovery/Refund Period October 1, 2022 through September 30, 2023

CapEx Revenue By Rate Class:

		Residential A-16 / A-60			Small C&I C-06			General C&I G-02			Demand B-32 / G-32		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-21	$625,234	$91,099	$534,135	$85,002	$22,092	$62,910	$200,487	$28,208	$172,279	$107,535	$27,231	$80,304
	May-21	$ 1,214,095.00	$172,484	$1,041,611	$ 216,943.00	$44,808	$172,135	$ 426,424.00	$55,017	$371,407	$ 434,484.00	$53,171	$381,313
	Jun-21	$ 1,583,770.00	$224,881	$1,358,889	$ 255,236.00	$50,093	$205,143	$ 502,864.00	$66,052	$436,812	$ 513,394.00	$61,660	$451,734
	Jul-21	$ 1,940,124.00	$275,449	$1,664,675	$ 279,681.00	$52,526	$227,155	$ 509,200.00	$71,826	$437,374	$ 575,320.00	$70,392	$504,928
	Aug-21	$ 2,192,208.00	$311,209	$1,880,999	$ 304,887.00	$55,370	$249,517	$ 526,744.00	$74,512	$452,232	$ 556,415.00	$68,199	$488,216
	Sep-21	$ 2,085,955.00	$296,264	$1,789,691	$ 301,396.00	$55,825	$245,571	$ 530,099.00	$75,678	$454,421	$ 530,291.00	$67,985	$462,306
	Oct-21	$ 1,315,632.00	$49,567	$1,266,065	$ 231,530.00	$28,889	$202,641	$ 472,707.00	$30,810	$441,897	$ 495,578.00	$25,022	$470,556
	Nov-21	$ 905,883.00	($131,363)	$1,037,246	$ 189,894.00	$6,356	$183,538	$ 410,518.00	($10,925)	$421,443	$ 381,042.00	($22,574)	$403,616
	Dec-21	$ 1,147,481.00	($166,666)	$1,314,147	$ 221,840.00	$7,217	$214,623	$ 380,230.00	($11,450)	$391,680	$ 398,443.00	($24,101)	$422,544
	Jan-22	$ 1,282,290.00	($186,261)	$1,468,551	$ 239,787.00	$7,418	$232,369	$ 340,350.00	($11,684)	$352,034	$ 416,074.00	($24,760)	$440,834
	Feb-22	$ 1,310,736.00	($190,389)	$1,501,125	$ 259,417.00	$8,115	$251,302	$ 423,511.00	($12,904)	$436,415	$ 401,282.00	($24,231)	$425,513
	Mar-22	$ 1,128,416.00	($163,934)	$1,292,350	$ 239,832.00	$7,920	$231,912	$ 409,414.00	($12,443)	$421,857	$ 415,212.00	($24,692)	$439,904
(2)	Apr-22	$657,317	($95,484)	$752,801	$166,415	$4,613	$161,802	$229,305	($7,247)	$236,552	$369,379	($14,384)	$383,763
	Total	$17,389,141	$486,856	$16,902,285	$2,991,860	$351,242	$2,640,618	$5,361,853	$335,450	$5,026,403	$5,594,449	$238,918	$5,355,531

		Lighting S-05/S-06/S-10/S-14			Propulsion X-01		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-21	$10,698	($1,001)	$11,699	$192	$49	$143
	May-21	$ 4,614.00	($5,303)	$9,917	$ 893.00	$120	$773
	Jun-21	$ 12,490.00	($5,187)	$17,677	$ 829.00	$110	$719
	Jul-21	$ 13,735.00	($4,148)	$17,883	$ 955.00	$126	$829
	Aug-21	$ 12,425.00	($3,731)	$16,156	$ 979.00	$130	$849
	Sep-21	$ 10,185.00	($2,095)	$12,280	$ 1,114.00	$147	$967
	Oct-21	$ 22,372.00	($2,275)	$24,647	$ 1,003.00	($57)	$1,060
	Nov-21	$ 25,378.00	$1,748	$23,630	$ 596.00	($312)	$908
	Dec-21	$ 24,834.00	$1,692	$23,142	$ 609.00	($336)	$945
	Jan-22	$ 27,738.00	$1,918	$25,820	$ 563.00	($311)	$874
	Feb-22	$ 22,489.00	$1,556	$20,933	$ 547.00	($303)	$850
	Mar-22	$ 31,184.00	$2,769	$28,415	$ 537.00	($297)	$834
(2)	Apr-22	$23,372	$1,613	$21,759	$313	($173)	$486
	Total	$241,514	($12,444)	$253,958	$9,130	($1,107)	$10,237

(1) Reflects revenue associated with consumption on and after April 1
(2) Reflects revenue associated with consumption prior to April 1

(a) From monthly revenue reports
(b) per Page 3 and Page 4
(c) Column (a) - Column (b)

The Narragansett Electric Company
d/b/a Rhode Island Energy
R.I.P.U.C. Docket No. 5098
FY 2022 Electric Infrastructure, Safety,
and Reliability Plan Reconciliation Filing
Attachment PRB-2
Page 2 of 4

Fiscal Year 2020 CapEx Reconciliation of Net Under Recovery
For the Period April 1, 2019 through March 31, 2020
For the Recovery/Refund Period October 1, 2020 through September 30, 2021

		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery	($4,568,740)		($2,614,827)		($533,322)		($780,044)		($720,190)
(2)	CapEx Reconciling Factors			$0.00090		$0.00085		$0.00064		$0.00033
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-20	$136,161	83,772,436	$75,395	20,217,566	$17,185	37,199,486	$23,808	68,180,372	$22,500
	Nov-20	$333,248	213,173,197	$191,856	45,313,632	$38,517	84,857,468	$54,309	166,467,949	$54,934
	Dec-20	$379,268	242,559,388	$218,303	52,446,367	$44,579	97,250,515	$62,240	184,218,265	$60,792
	Jan-21	$427,325	289,932,081	$260,939	58,941,502	$50,100	97,437,231	$62,360	183,977,489	$60,713
	Feb-21	$416,701	272,865,133	$245,579	59,302,826	$50,407	102,485,125	$65,590	182,539,180	$60,238
	Mar-21	$391,299	246,033,617	$221,430	58,108,508	$49,392	101,710,253	$65,095	186,432,252	$61,523
	Apr-21	$359,437	216,978,793	$195,281	55,714,011	$47,357	94,478,594	$60,466	176,885,284	$58,372
	May-21	$320,297	191,648,822	$172,484	52,715,880	$44,808	85,963,985	$55,017	161,123,392	$53,171
	Jun-21	$397,609	249,867,400	$224,881	58,932,384	$50,093	103,205,929	$66,052	186,848,760	$61,660
	Jul-21	$466,171	306,054,988	$275,449	61,795,083	$52,526	112,228,149	$71,826	213,309,709	$70,392
	Aug-21	$505,689	345,787,720	$311,209	65,141,290	$55,370	116,424,354	$74,512	206,663,559	$68,199
	Sep-21	$493,804	329,182,062	$296,264	65,676,737	$55,825	118,247,287	$75,678	206,015,820	$67,985
(4)	Oct-21	$212,075	130,671,844	$117,605	30,470,607	$25,900	56,075,449	$35,888	107,900,310	$35,607
(5)	Total	$4,839,084		$2,806,675		$582,059		$772,841		$736,086
(6)	Ending Over/(Under) Recovery	$270,344		$191,848		$48,737		($7,203)		$15,896

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		$81,645		($2,003)
(2)	CapEx Reconciling Factors		($0.00159)		$0.00009
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-20	1,739,246	($2,765)	424,970	$38
	Nov-20	4,071,678	($6,474)	1,176,896	$106
	Dec-20	4,249,574	($6,757)	1,237,157	$111
	Jan-21	4,331,664	($6,887)	1,111,449	$100
	Feb-21	3,281,276	($5,217)	1,156,720	$104
	Mar-21	3,926,393	($6,243)	1,137,439	$102
	Apr-21	1,349,084	($2,145)	1,175,722	$106
	May-21	3,335,399	($5,303)	1,334,216	$120
	Jun-21	3,262,024	($5,187)	1,218,578	$110
	Jul-21	2,608,651	($4,148)	1,403,962	$126
	Aug-21	2,346,579	($3,731)	1,439,772	$130
	Sep-21	1,317,892	($2,095)	1,638,411	$147
(4)	Oct-21	1,887,183	($3,001)	840,301	$76
(5)	Total		($59,953)		$1,376
(6)	Ending Over/(Under) Recovery		$21,692		($627)

(1) Docket No. 4915, Attachment ASC-2 Compliance, Page 1, Line (8)
(2) Docket No. 4915, Attachment ASC-2 Compliance, Page 1, Line (1(
(3) Prorated for usage on and after October 1, 2020
(4) Prorated for usage prior to October 1, 2021
(5) Sum of kWhs & revenue
(6) Line (1) + Line (5)

(a) Sum of Column (b) from each rate
(b) From Company revenue report
(c) Column (b) x Line (2) CapEx Reconciling Factor

The Narragansett Electric Company
d/b/a Rhode Island Energy
R.I.P.U.C. Docket No. 5098
FY 2022 Electric Infrastructure, Safety,
and Reliability Plan Reconciliation Filing
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The Narragansett Electric Company
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and Reliability Plan Reconciliation Filing
Attachment PRB-2
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Fiscal Year 2021 CapEx Reconciliation of Net Over Recovery
For the Period April 1, 2020 through March 31, 2021
For the Recovery/Refund Period October 1, 2021 through September 30, 2022

		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery	$2,404,073		$2,083,030		($85,823)		$139,972		$288,697
(2)	CapEx Reconciling Factors			($0.00069)		$0.00013		($0.00012)		($0.00013)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-21	($80,119)	98,605,668	($68,038)	22,993,282	$2,989	42,314,832	($5,078)	81,422,147	($10,585)
	Nov-21	($157,070)	190,381,543	($131,363)	48,889,383	$6,356	91,042,777	($10,925)	173,647,566	($22,574)
	Dec-21	($193,644)	241,544,671	($166,666)	55,513,579	$7,217	95,417,392	($11,450)	185,393,324	($24,101)
	Jan-22	($213,680)	269,943,916	($186,261)	57,064,601	$7,418	97,368,925	($11,684)	190,461,789	($24,760)
	Feb-22	($218,156)	275,925,654	($190,389)	62,419,470	$8,115	107,533,315	($12,904)	186,394,762	($24,231)
	Mar-22	($190,677)	237,585,313	($163,934)	60,919,900	$7,920	103,690,927	($12,443)	189,940,474	($24,692)
	Apr-22	($177,798)	219,302,240	($151,319)	58,598,144	$7,618	99,132,350	($11,896)	182,235,879	($23,691)
	May-22	($163,439)	200,054,146	($138,037)	56,711,733	$7,373	92,548,324	($11,106)	174,258,561	($22,654)
	Jun-22	($175,678)	216,361,105	($149,289)	57,067,906	$7,419	93,712,264	($11,245)	184,897,219	($24,037)
	Jul-22	$0	-	$0	-	$0	-	$0	-	$0
	Aug-22	$0	-	$0	-	$0	-	$0	-	$0
(4)	Sep-22	$0	-	$0	-	$0	-	$0	-	$0
(5)	Total	($1,570,261)		($1,345,296)		$62,425		($98,731)		($201,325)
(6)	Ending Over/(Under) Recovery	$833,812		$737,734		($23,398)		$41,241		$87,372

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		($24,723)		$2,920
(2)	CapEx Reconciling Factors		$0.00051		($0.00021)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-21	1,424,078	$726	634,095	($133)
	Nov-21	3,427,078	$1,748	1,486,229	($312)
	Dec-21	3,317,832	$1,692	1,601,387	($336)
	Jan-22	3,761,764	$1,918	1,480,858	($311)
	Feb-22	3,051,917	$1,556	1,440,742	($303)
	Mar-22	5,429,953	$2,769	1,413,298	($297)
	Apr-22	3,534,580	$1,803	1,489,697	($313)
	May-22	2,560,151	$1,306	1,530,465	($321)
	Jun-22	3,613,012	$1,843	1,756,149	($369)
	Jul-22	-	$0	-	$0
	Aug-22	-	$0	-	$0
(4)	Sep-22	-	$0	-	$0
(5)	Total		$15,361		($2,695)
(6)	Ending Over/(Under) Recovery		($9,362)		$225

(1) Docket No. 4995, Schedule DEG-2, Page 1 of 4, line (8)
(2) Docket No. 4995, Schedule DEG-2, Page 1 of 4, line (8)
(3) Prorated for usage on and after October 1, 2021
(4) Prorated for usage prior to October 1, 2022
(5) Sum of kWhs & revenue
(6) Line (1) + Line (5)

(a) Sum of Column (b) from each rate
(b) From Company revenue report
(c) Column (b) x Line (2) CapEx Reconciling Factor

Attachment PRB-3

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2022 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For Fiscal Year 2022 ISR Plan
For the Recovery/(Refund) Period October 1, 2022 through September 30, 2023

(1)	Actual FY 2022 O&M Revenue Requirement	$12,081,003
(2)	O&M Revenue Billed	$12,177,331
(3)	Total Over/(Under) Recovery for FY 2022	$96,328
(4)	Remaining Over/(Under) For FY 2020	($26,500)
(5)	Total Over/(Under) Recovery	$69,828
(6)	Forecasted kWhs - October 1, 2022 through September 30, 2023	7,399,766,076
(7)	Proposed O&M Reconciling Factor Charge/(Credit) per kWh	$0.00000

(1) per Attachment SAB/JDO-1, Page 1, Line (4), Column (b)
(2) per Page 2
(3) Line (2) - Line (1)
(4) per Page 3, Line (4)
(5) Line (3) + Line (4)
(6) per Company forecast
(7) [Line (5) ÷ Line (6)] x -1, truncated to 5 decimal places

Fiscal Year 2022 Operations & Maintenance Reconciliation
For the Period April 1, 2021 through March 31, 2022
For the Recovery/Refund Period October 1, 2022 through September 30, 2023

O&M Factor Revenue:

	Month	O&M Revenue (a)	Prior Period Reconciliation Factor Revenue (b)	Base O&M Revenue (c)
(1)	Apr-21	$415,349	$5,100	$410,249
	May-21	$805,910	$9,922	$795,988
	Jun-21	$1,002,883	$12,067	$990,816
	Jul-21	$1,161,982	$13,948	$1,148,034
	Aug-21	$1,251,898	$14,756	$1,237,142
	Sep-21	$1,208,507	$14,442	$1,194,065
	Oct-21	$928,058	($18,182)	$946,240
	Nov-21	$777,565	($50,887)	$828,452
	Dec-21	$905,267	($58,279)	$963,546
	Jan-22	$979,076	($62,008)	$1,041,084
	Feb-22	$1,004,360	($63,677)	$1,068,037
	Mar-22	$944,115	($59,898)	$1,004,013
(2)	Apr-22	$514,777	($34,888)	$549,665
	Total	$11,899,747	($277,584)	$12,177,331

(1) Reflects kWhs consumed on and after April 1
(2) Reflects kWhs consumed prior to April 1

(a) From monthly revenue reports
(b) per Page 3 and Page 4
(c) Column (a) - Column (b)

Fiscal Year 2020 O&M Reconciliation of Under Recovery
For the Period April 1, 2019 through March 31, 2020
For the Recovery/Refund Period October 1, 2020 through September 30, 2021

		Total
(1)	Over/(Under) Recovery	($172,390)
(2)	O&M Reconciling Factor	$0.00002

		Total kWhs (a)	Total Revenue (b)
	Oct-20	211,534,076	$4,231
	Nov-20	515,060,820	$10,301
	Dec-20	581,961,266	$11,639
	Jan-21	635,731,416	$12,715
	Feb-21	621,630,260	$12,433
	Mar-21	597,348,462	$11,947
	Apr-21	546,581,488	$10,932
	May-21	496,121,694	$9,922
	Jun-21	603,335,075	$12,067
	Jul-21	697,400,542	$13,948
	Aug-21	737,803,274	$14,756
	Sep-21	722,078,209	$14,442
	Oct-21	327,845,693	$6,557
(3)	Total	7,294,432,275	$145,890
(4)	Ending Over/(Under) Recovery		($26,500)

(1) Docket No. 4915, Attachment ASC-3 page 1, line (5)
(2) Docket No. 4915, Attachment ASC-3 page 1, line (7)
(3) Sum of kWhs & revenue
(4) Line (1) + Line (3)

(a) per Company Records
(b) Line (2) x Column (a)

Fiscal Year 2021 O&M Reconciliation of Over Recovery
For the Period April 1, 2020 through March 31, 2021
For the Recovery/Refund Period October 1, 2021 through September 30, 2022

		Total	
(1)	Over/(Under) Recovery	$743,647	
(2)	O&M Reconciling Factor	($0.00010)	
		Total kWhs (a)	Total Revenue (b)
	Oct-21	247,394,103	($24,739)
	Nov-21	508,874,576	($50,887)
	Dec-21	582,788,185	($58,279)
	Jan-22	620,081,853	($62,008)
	Feb-22	636,765,860	($63,677)
	Mar-22	598,979,865	($59,898)
	Apr-22	564,292,890	($56,429)
	May-22	527,663,380	($52,766)
	Jun-22	557,407,655	($55,741)
	Jul-22	-	$0
	Aug-22	-	$0
	Sep-22	-	$0
	Oct-22	-	$0
(3)	Total	4,844,248,367	($484,424)
(4)	Ending Over/(Under) Recovery		$259,223

(1) Docket No. 4995, Attachment DEG-3 page 1, line (5)
(2) Docket No. 4995, Attachment DEG-3 page 1, line (7)
(3) Sum of kWhs & revenue
(4) Line (1) + Line (3)

(a) per Company Records
(b) Line (2) x Column (a)

Attachment PRB-4

Typical Bill Analysis

The Narragansett Electric Company
d/b/a Rhode Island Energy
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-16 Rate Customers

	Rates Effective July 1, 2022				Proposed Rates Effective October 1, 2022				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	of Customers
(a)	(b)	(c)	(d)	(e) = (a) + (b) + (c)	(f)	(g)	(h)	(i) = (f) + (g) + (h)	(j) = (f) - (b)	(k) = (g) - (c)	(l) = (h) - (d)	(m) = (j) + (k) + (l)	(n) = (j) / (e)	(o) = (k) / (e)	(p) = (l) / (e)	(q) = (m) / (e)	(r)
150	$26.77	$11.72	$1.60	$40.09	$26.75	$11.72	$1.60	$40.07	($0.02)	$0.00	$0.00	($0.02)	0.0%	0.0%	0.0%	0.0%	30.1%
300	$44.29	$23.43	$2.82	$70.54	$44.26	$23.43	$2.82	$70.51	($0.03)	$0.00	$0.00	($0.03)	0.0%	0.0%	0.0%	0.0%	12.9%
400	$55.97	$31.24	$3.63	$90.84	$55.93	$31.24	$3.63	$90.80	($0.04)	$0.00	$0.00	($0.04)	0.0%	0.0%	0.0%	0.0%	11.6%
500	$67.65	$39.05	$4.45	$111.15	$67.60	$39.05	$4.44	$111.09	($0.05)	$0.00	($0.01)	($0.06)	0.0%	0.0%	0.0%	-0.1%	9.6%
600	$79.32	$46.86	$5.26	$131.44	$79.26	$46.86	$5.26	$131.38	($0.06)	$0.00	$0.00	($0.06)	0.0%	0.0%	0.0%	0.0%	7.7%
700	$91.00	$54.67	$6.07	$151.74	$90.93	$54.67	$6.07	$151.67	($0.07)	$0.00	$0.00	($0.07)	0.0%	0.0%	0.0%	0.0%	19.0%
1,200	$149.40	$93.72	$10.13	$253.25	$149.28	$93.72	$10.13	$253.13	($0.12)	$0.00	$0.00	($0.12)	0.0%	0.0%	0.0%	0.0%	6.8%
2,000	$242.83	$156.20	$16.63	$415.66	$242.63	$156.20	$16.62	$415.45	($0.20)	$0.00	($0.01)	($0.21)	0.0%	0.0%	0.0%	-0.1%	2.3%

			Rates Effective July 1, 2022 (s)	Proposed Rates Effective October 1, 2022 (t)	Line Item on Bill
(1)	Distribution Customer Charge		$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge		$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge		$2.46	$2.46	RE Growth Program
(4)	Distribution Charge (per kWh)		$0.04580	$0.04580	
(5)	Operating & Maintenance Expense Charge		$0.00211	$0.00211	
(6)	Operating & Maintenance Expense Reconciliation Factor		($0.00010)	$0.00000	
(7)	CapEx Factor Charge		$0.00639	$0.00639	
(8)	CapEx Reconciliation Factor		($0.00069)	($0.00089)	
(9)	Revenue Decoupling Adjustment Factor		($0.00003)	($0.00003)	Distribution Energy Charge
(10)	Pension Adjustment Factor		($0.00006)	($0.00006)	
(11)	Storm Fund Replenishment Factor		$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor		$0.00007	$0.00007	
(13)	Performance Incentive Factor		$0.00012	$0.00012	
(14)	Low Income Discount Recovery Factor		$0.00238	$0.00238	
(15)	Long-term Contracting for Renewable Energy Charge		($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16)	Net Metering Charge		$0.00488	$0.00488	
(17)	Base Transmission Charge		$0.03524	$0.03524	
(18)	Transmission Adjustment Factor		$0.00095	$0.00095	Transmission Charge
(19)	Transmission Uncollectible Factor		$0.00046	$0.00046	
(20)	Base Transition Charge		$0.00000	$0.00000	Transition Charge
(21)	Transition Adjustment		$0.00018	$0.00018	
(22)	Energy Efficiency Program Charge		$0.01252	$0.01252	Energy Efficiency Programs
(23)	Last Resort Service Base Charge		$0.07174	$0.07174	
(24)	LRS Adjustment Factor		($0.00318)	($0.00318)	Supply Services Energy Charge
(25)	LRS Adminstrative Cost Adjustment Factor		$0.00233	$0.00233	
(26)	Renewable Energy Standard Charge		$0.00721	$0.00721	
	Line Item on Bill				
(27)	Customer Charge		$6.00	$6.00	
(28)	LIHEAP Enhancement Charge		$0.79	$0.79	
(29)	RE Growth Program		$2.46	$2.46	
(30)	Transmission Charge	kWh x	$0.03665	$0.03665	
(31)	Distribution Energy Charge	kWh x	$0.06387	$0.06377	
(32)	Transition Charge	kWh x	$0.00018	$0.00018	
(33)	Energy Efficiency Programs	kWh x	$0.01252	$0.01252	
(34)	Renewable Energy Distribution Charge	kWh x	$0.00357	$0.00357	
(35)	Supply Services Energy Charge	kWh x	$0.07810	$0.07810	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022
Column (t): Line (6) per Attachment PRB-3, Page 1, Line (7). Line (8) per Attachment PRB-2, Page 1, Line (10).All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022

The Narragansett Electric Company
d/b/a Rhode Island Energy
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

	Rates Effective July 1, 2022						Proposed Rates Effective October 1, 2022						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	of Customers
				(e) = (b) + (c) + (d)						(k) = (h) + (i) + (j)			(n) = [(h)+(j)] - [(b)+(d)]			(q) = (n) + (o) + (p)					
(a)	(b)	(c)	(d) = [(b)+(c)] x-.25		(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.25		(l)	(m) = (k) + (l)		(o) = (i) - (c)	(p) = (l) - (f)		(r) = (n) / (g)	(s) = (o) / (g)	(t) = (p) / (g)	(u) = (q) / (g)	(v)
150	$26.41	$11.72	($9.53)	$28.60	$1.19	$29.79	$26.40	$11.72	($9.53)	$28.59	$1.19	$29.78	($0.01)	$0.00	$0.00	($0.01)	0.0%	0.0%	0.0%	0.0%	32.1%
300	$43.57	$23.43	($16.75)	$50.25	$2.09	$52.34	$43.54	$23.43	($16.74)	$50.23	$2.09	$52.32	($0.02)	$0.00	$0.00	($0.02)	0.0%	0.0%	0.0%	0.0%	15.4%
400	$55.01	$31.24	($21.56)	$64.69	$2.70	$67.39	$54.97	$31.24	($21.55)	$64.66	$2.69	$67.35	($0.03)	$0.00	($0.01)	($0.04)	0.0%	0.0%	0.0%	-0.1%	12.5%
500	$66.46	$39.05	($26.38)	$79.13	$3.30	$82.43	$66.41	$39.05	($26.37)	$79.09	$3.30	$82.39	($0.04)	$0.00	$0.00	($0.04)	0.0%	0.0%	0.0%	0.0%	9.6%
600	$77.90	$46.86	($31.19)	$93.57	$3.90	$97.47	$77.84	$46.86	($31.18)	$93.52	$3.90	$97.42	($0.05)	$0.00	$0.00	($0.05)	-0.1%	0.0%	0.0%	-0.1%	7.2%
700	$89.34	$54.67	($36.00)	$108.01	$4.50	$112.51	$89.27	$54.67	($35.99)	$107.95	$4.50	$112.45	($0.06)	$0.00	$0.00	($0.06)	-0.1%	0.0%	0.0%	-0.1%	16.4%
1,200	$146.54	$93.72	($60.07)	$180.19	$7.51	$187.70	$146.42	$93.72	($60.04)	$180.10	$7.50	$187.60	($0.09)	$0.00	($0.01)	($0.10)	0.0%	0.0%	0.0%	-0.1%	5.2%
2,000	$238.07	$156.20	($98.57)	$295.70	$12.32	$308.02	$237.87	$156.20	($98.52)	$295.55	$12.31	$307.86	($0.15)	$0.00	($0.01)	($0.16)	0.0%	0.0%	0.0%	-0.1%	1.6%

		Rates Effective July 1, 2022	Proposed Rates Effective October 1, 2022	Line Item on Bill
		(w)	(x)	
(1)	Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$2.46	$2.46	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge	$0.00211	$0.00211	
(6)	Operating & Maintenance Expense Reconciliation Factor	($0.00010)	$0.00000	
(7)	CapEx Factor Charge	$0.00639	$0.00639	
(8)	CapEx Reconciliation Factor	($0.00069)	($0.00089)	
(9)	Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	
(10)	Pension Adjustment Factor	($0.00006)	($0.00006)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(13)	Performance Incentive Factor	$0.00012	$0.00012	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00488	$0.00488	
(17)	Base Transmission Charge	$0.03524	$0.03524	Transmission Charge
(18)	Transmission Adjustment Factor	$0.00095	$0.00095	
(19)	Transmission Uncollectible Factor	$0.00046	$0.00046	
(20)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(21)	Transition Adjustment	$0.00018	$0.00018	
(22)	Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(23)	Last Resort Service Base Charge	$0.07174	$0.07174	Supply Services Energy Charge
(24)	LRS Adjustment Factor	($0.00318)	($0.00318)	
(25)	LRS Adminstrative Cost Adjustment Factor	$0.00233	$0.00233	
(26)	Renewable Energy Standard Charge	$0.00721	$0.00721	
	Line Item on Bill			
(27)	Customer Charge	$6.00	$6.00	
(28)	LIHEAP Enhancement Charge	$0.79	$0.79	
(29)	RE Growth Program	$2.46	$2.46	
(30)	Transmission Charge	$0.03665	$0.03665	
(31)	Distribution Energy Charge	$0.06149	$0.06139	
(32)	Transition Charge	$0.00018	$0.00018	
(33)	Energy Efficiency Programs	$0.01252	$0.01252	
(34)	Renewable Energy Distribution Charge	$0.00357	$0.00357	
(35)	Supply Services Energy Charge	$0.07810	$0.07810	
(36)	Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022
Column (x): Line (6) per Attachment PRB-3, Page 1, Line (7). Line (8) per Attachment PRB-2, Page 1, Line (10).All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022

The Narragansett Electric Company
d/b/a Rhode Island Energy
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

Monthly kWh	Rates Effective July 1, 2022						Proposed Rates Effective October 1, 2022						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage of Customers
	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	
(a)	(b)	(c)	(d) = [(b)+(c)] x-.30	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.30	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) / (g)	(s) = (o) / (g)	(t) = (p) / (g)	(u) = (q) / (g)	(v)
150	$26.41	$11.72	($11.44)	$26.69	$1.11	$27.80	$26.40	$11.72	($11.44)	$26.68	$1.11	$27.79	($0.01)	$0.00	$0.00	($0.01)	0.0%	0.0%	0.0%	0.0%	32.1%
300	$43.57	$23.43	($20.10)	$46.90	$1.95	$48.85	$43.54	$23.43	($20.09)	$46.88	$1.95	$48.83	($0.02)	$0.00	$0.00	($0.02)	0.0%	0.0%	0.0%	0.0%	15.4%
400	$55.01	$31.24	($25.88)	$60.37	$2.52	$62.89	$54.97	$31.24	($25.86)	$60.35	$2.51	$62.86	($0.02)	$0.00	($0.01)	($0.03)	0.0%	0.0%	0.0%	0.0%	12.5%
500	$66.46	$39.05	($31.65)	$73.86	$3.08	$76.94	$66.41	$39.05	($31.64)	$73.82	$3.08	$76.90	($0.04)	$0.00	$0.00	($0.04)	-0.1%	0.0%	0.0%	-0.1%	9.6%
600	$77.90	$46.86	($37.43)	$87.33	$3.64	$90.97	$77.84	$46.86	($37.41)	$87.29	$3.64	$90.93	($0.04)	$0.00	$0.00	($0.04)	0.0%	0.0%	0.0%	0.0%	7.2%
700	$89.34	$54.67	($43.20)	$100.81	$4.20	$105.01	$89.27	$54.67	($43.18)	$100.76	$4.20	$104.96	($0.05)	$0.00	$0.00	($0.05)	0.0%	0.0%	0.0%	0.0%	16.4%
1,200	$146.54	$93.72	($72.08)	$168.18	$7.01	$175.19	$146.42	$93.72	($72.04)	$168.10	$7.00	$175.10	($0.08)	$0.00	($0.01)	($0.09)	0.0%	0.0%	0.0%	-0.1%	5.2%
2,000	$238.07	$156.20	($118.28)	$275.99	$11.50	$287.49	$237.87	$156.20	($118.22)	$275.85	$11.49	$287.34	($0.14)	$0.00	($0.01)	($0.15)	0.0%	0.0%	0.0%	-0.1%	1.6%

		Rates Effective July 1, 2022 (w)	Proposed Rates Effective October 1, 2022 (x)	Line Item on Bill
(1)	Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$2.46	$2.46	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5)	Operating & Maintenance Expense Charge	$0.00211	$0.00211	
(6)	Operating & Maintenance Expense Reconciliation Factor	($0.00010)	$0.00000	
(7)	CapEx Factor Charge	$0.00639	$0.00639	
(8)	CapEx Reconciliation Factor	($0.00069)	($0.00089)	
(9)	Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	
(10)	Pension Adjustment Factor	($0.00006)	($0.00006)	
(11)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12)	Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(13)	Performance Incentive Factor	$0.00012	$0.00012	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00488	$0.00488	
(17)	Base Transmission Charge	$0.03524	$0.03524	Transmission Charge
(18)	Transmission Adjustment Factor	$0.00095	$0.00095	
(19)	Transmission Uncollectible Factor	$0.00046	$0.00046	
(20)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(21)	Transition Adjustment	$0.00018	$0.00018	
(22)	Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(23)	Last Resort Service Base Charge	$0.07174	$0.07174	Supply Services Energy Charge
(24)	LRS Adjustment Factor	($0.00318)	($0.00318)	
(25)	LRS Adminstrative Cost Adjustment Factor	$0.00233	$0.00233	
(26)	Renewable Energy Standard Charge	$0.00721	$0.00721	
	Line Item on Bill			
(27)	Customer Charge	$6.00	$6.00	
(28)	LIHEAP Enhancement Charge	$0.79	$0.79	
(29)	RE Growth Program	$2.46	$2.46	
(30)	Transmission Charge	$0.03665	$0.03665	
(31)	Distribution Energy Charge	$0.06149	$0.06139	
(32)	Transition Charge	$0.00018	$0.00018	
(33)	Energy Efficiency Programs	$0.01252	$0.01252	
(34)	Renewable Energy Distribution Charge	$0.00357	$0.00357	
(35)	Supply Services Energy Charge	$0.07810	$0.07810	
(36)	Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022
Column (x): Line (6) per Attachment PRB-3, Page 1, Line (7). Line (8) per Attachment PRB-2, Page 1, Line (10).All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022

The Narragansett Electric Company
d/b/a Rhode Island Energy
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to C-06 Rate Customers

	Rates Effective July 1, 2022				Proposed Rates Effective October 1, 2022				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh (a)	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)	of Customers (r)
250	$42.72	$20.12	$2.62	$65.46	$42.69	$20.12	$2.62	$65.43	($0.03)	$0.00	$0.00	($0.03)	0.0%	0.0%	0.0%	0.0%	56.3%
500	$70.87	$40.24	$4.63	$115.74	$70.82	$40.24	$4.63	$115.69	($0.05)	$0.00	$0.00	($0.05)	0.0%	0.0%	0.0%	0.0%	16.9%
1,000	$127.16	$80.47	$8.65	$216.28	$127.06	$80.47	$8.65	$216.18	($0.10)	$0.00	$0.00	($0.10)	0.0%	0.0%	0.0%	0.0%	8.1%
1,500	$183.46	$120.71	$12.67	$316.84	$183.31	$120.71	$12.67	$316.69	($0.15)	$0.00	$0.00	($0.15)	0.0%	0.0%	0.0%	0.0%	5.0%
2,000	$239.75	$160.94	$16.70	$417.39	$239.55	$160.94	$16.69	$417.18	($0.20)	$0.00	($0.01)	($0.21)	0.0%	0.0%	0.0%	-0.1%	13.6%

	Rates Effective July 1, 2022 (s)	Proposed Rates Effective October 1, 2022 (t)	Line Item on Bill
(1) Distribution Customer Charge	$10.00	$10.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$3.78	$3.78	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04482	$0.04482	Distribution Energy Charge
(5) Operating & Maintenance Expense Charge	$0.00211	$0.00211	
(6) Operating & Maintenance Expense Reconciliation Factor	($0.00010)	$0.00000	
(7) CapEx Factor Charge	$0.00543	$0.00543	
(8) CapEx Reconciliation Factor	$0.00013	($0.00007)	
(9) Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	
(10) Pension Adjustment Factor	($0.00006)	($0.00006)	
(11) Storm Fund Replenishment Factor	$0.00788	$0.00788	
(12) Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(13) Performance Incentive Factor	$0.00012	$0.00012	
(14) Low Income Discount Recovery Factor	$0.00238	$0.00238	
(15) Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(16) Net Metering Charge	$0.00488	$0.00488	
(17) Base Transmission Charge	$0.03540	$0.03540	Transmission Charge
(18) Transmission Adjustment Factor	($0.00219)	($0.00219)	
(19) Transmission Uncollectible Factor	$0.00036	$0.00036	
(20) Base Transition Charge	$0.00000	$0.00000	Transition Charge
(21) Transition Adjustment	$0.00018	$0.00018	
(22) Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(23) Last Resort Service Base Charge	$0.06451	$0.06451	Supply Services Energy Charge
(24) LRS Adjustment Factor	$0.00665	$0.00665	
(25) LRS Adminstrative Cost Adjustment Factor	$0.00210	$0.00210	
(26) Renewable Energy Standard Charge	$0.00721	$0.00721	
Line Item on Bill			
(27) Customer Charge	$10.00	$10.00	
(28) LIHEAP Enhancement Charge	$0.79	$0.79	
(29) RE Growth Program	$3.78	$3.78	
(30) Transmission Charge	$0.03357	$0.03357	
(31) Distribution Energy Charge	$0.06275	$0.06265	
(32) Transition Charge	$0.00018	$0.00018	
(33) Energy Efficiency Programs	$0.01252	$0.01252	
(34) Renewable Energy Distribution Charge	$0.00357	$0.00357	
(35) Supply Services Energy Charge	$0.08047	$0.08047	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022
Column (t): Line (6) per Attachment PRB-3, Page 1, Line (7). Line (8) per Attachment PRB-2, Page 1, Line (10).All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022

The Narragansett Electric Company
d/b/a Rhode Island Energy
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

			Rates Effective July 1, 2022				Proposed Rates Effective October 1, 2022				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)
20	200	4,000	$541.61	$321.88	$35.98	$899.47	$539.61	$321.88	$35.90	$897.39	($2.00)	$0.00	($0.08)	($2.08)	-0.2%	0.0%	0.0%	-0.2%
50	200	10,000	$1,206.53	$804.70	$83.80	$2,095.03	$1,201.53	$804.70	$83.59	$2,089.82	($5.00)	$0.00	($0.21)	($5.21)	-0.2%	0.0%	0.0%	-0.2%
100	200	20,000	$2,314.73	$1,609.40	$163.51	$4,087.64	$2,304.73	$1,609.40	$163.09	$4,077.22	($10.00)	$0.00	($0.42)	($10.42)	-0.2%	0.0%	0.0%	-0.3%
150	200	30,000	$3,422.93	$2,414.10	$243.21	$6,080.24	$3,407.93	$2,414.10	$242.58	$6,064.61	($15.00)	$0.00	($0.63)	($15.63)	-0.2%	0.0%	0.0%	-0.3%
20	300	6,000	$627.75	$482.82	$46.27	$1,156.84	$624.75	$482.82	$46.15	$1,153.72	($3.00)	$0.00	($0.12)	($3.12)	-0.3%	0.0%	0.0%	-0.3%
50	300	15,000	$1,421.88	$1,207.05	$109.54	$2,738.47	$1,414.38	$1,207.05	$109.23	$2,730.66	($7.50)	$0.00	($0.31)	($7.81)	-0.3%	0.0%	0.0%	-0.3%
100	300	30,000	$2,745.43	$2,414.10	$214.98	$5,374.51	$2,730.43	$2,414.10	$214.36	$5,358.89	($15.00)	$0.00	($0.62)	($15.62)	-0.3%	0.0%	0.0%	-0.3%
150	300	45,000	$4,068.98	$3,621.15	$320.42	$8,010.55	$4,046.48	$3,621.15	$319.48	$7,987.11	($22.50)	$0.00	($0.94)	($23.44)	-0.3%	0.0%	0.0%	-0.3%
20	400	8,000	$713.89	$643.76	$56.57	$1,414.22	$709.89	$643.76	$56.40	$1,410.05	($4.00)	$0.00	($0.17)	($4.17)	-0.3%	0.0%	0.0%	-0.3%
50	400	20,000	$1,637.23	$1,609.40	$135.28	$3,381.91	$1,627.23	$1,609.40	$134.86	$3,371.49	($10.00)	$0.00	($0.42)	($10.42)	-0.3%	0.0%	0.0%	-0.3%
100	400	40,000	$3,176.13	$3,218.80	$266.46	$6,661.39	$3,156.13	$3,218.80	$265.62	$6,640.55	($20.00)	$0.00	($0.84)	($20.84)	-0.3%	0.0%	0.0%	-0.3%
150	400	60,000	$4,715.03	$4,828.20	$397.63	$9,940.86	$4,685.03	$4,828.20	$396.38	$9,909.61	($30.00)	$0.00	($1.25)	($31.25)	-0.3%	0.0%	0.0%	-0.3%
20	500	10,000	$800.03	$804.70	$66.86	$1,671.59	$795.03	$804.70	$66.66	$1,666.39	($5.00)	$0.00	($0.20)	($5.20)	-0.3%	0.0%	0.0%	-0.3%
50	500	25,000	$1,852.58	$2,011.75	$161.01	$4,025.34	$1,840.08	$2,011.75	$160.49	$4,012.32	($12.50)	$0.00	($0.52)	($13.02)	-0.3%	0.0%	0.0%	-0.3%
100	500	50,000	$3,606.83	$4,023.50	$317.93	$7,948.26	$3,581.83	$4,023.50	$316.89	$7,922.22	($25.00)	$0.00	($1.04)	($26.04)	-0.3%	0.0%	0.0%	-0.3%
150	500	75,000	$5,361.08	$6,035.25	$474.85	$11,871.18	$5,323.58	$6,035.25	$473.28	$11,832.11	($37.50)	$0.00	($1.57)	($39.07)	-0.3%	0.0%	0.0%	-0.3%
20	600	12,000	$886.17	$965.64	$77.16	$1,928.97	$880.17	$965.64	$76.91	$1,922.72	($6.00)	$0.00	($0.25)	($6.25)	-0.3%	0.0%	0.0%	-0.3%
50	600	30,000	$2,067.93	$2,414.10	$186.75	$4,668.78	$2,052.93	$2,414.10	$186.13	$4,653.16	($15.00)	$0.00	($0.62)	($15.62)	-0.3%	0.0%	0.0%	-0.3%
100	600	60,000	$4,037.53	$4,828.20	$369.41	$9,235.14	$4,007.53	$4,828.20	$368.16	$9,203.89	($30.00)	$0.00	($1.25)	($31.25)	-0.3%	0.0%	0.0%	-0.3%
150	600	90,000	$6,007.13	$7,242.30	$552.06	$13,801.49	$5,962.13	$7,242.30	$550.18	$13,754.61	($45.00)	$0.00	($1.88)	($46.88)	-0.3%	0.0%	0.0%	-0.3%

		Rates Effective July 1, 2022 (r)	Proposed Rates Effective October 1, 2022 (s)	Line Item on Bill
(1)	Distribution Customer Charge	$145.00	$145.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$38.34	$38.34	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 10kW)	$6.90	$6.90	Distribution Demand Charge
(5)	CapEx Factor Demand Charge (per kW > 10kW)	$1.68	$1.68	
(6)	Distribution Charge (per kWh)	$0.00476	$0.00476	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00183	$0.00183	
(8)	Operating & Maintenance Expense Reconciliation Factor	($0.00010)	$0.00000	
(9)	CapEx Reconciliation Factor	($0.00012)	($0.00072)	
(10)	Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	
(11)	Pension Adjustment Factor	($0.00006)	($0.00006)	
(12)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13)	Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(14)	Performance Incentive Factor	$0.00012	$0.00012	
(15)	Low Income Discount Recovery Factor	$0.00238	$0.00238	
(16)	Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.00488	$0.00488	
(18)	Transmission Demand Charge	$4.97	$4.97	Transmission Demand Charge
(19)	Base Transmission Charge	$0.01342	$0.01342	Transmission Adjustment
(20)	Transmission Adjustment Factor	($0.00371)	($0.00371)	
(21)	Transmission Uncollectible Factor	$0.00036	$0.00036	
(22)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(23)	Transition Adjustment	$0.00018	$0.00018	
(24)	Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(25)	Last Resort Service Base Charge	$0.06451	$0.06451	Supply Services Energy Charge
(26)	LRS Adjustment Factor	$0.00665	$0.00665	
(27)	LRS Adminstrative Cost Adjustment Factor	$0.00210	$0.00210	
(28)	Renewable Energy Standard Charge	$0.00721	$0.00721	
	Line Item on Bill			
(29)	Customer Charge	$145.00	$145.00	
(31)	LIHEAP Enhancement Charge	$0.79	$0.79	
(30)	RE Growth Program	$38.34	$38.34	
(32)	Transmission Adjustment	$0.01007	$0.01007	
(33)	Distribution Energy Charge	$0.01673	$0.01623	
(34)	Distribution Demand Charge	$8.58	$8.58	
(35)	Transmission Demand Charge	$4.97	$4.97	
(34)	Transition Charge	$0.00018	$0.00018	
(35)	Energy Efficiency Programs	$0.01252	$0.01252	
(36)	Renewable Energy Distribution Charge	$0.00357	$0.00357	
(37)	Supply Services Energy Charge	$0.08047	$0.08047	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022
Column (s): Line (8) per Attachment PRB-3, Page 1, Line (7). Line (9) per Attachment PRB-2, Page 1, Line (10).All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022

The Narragansett Electric Company
d/b/a Rhode Island Energy
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

			Rates Effective July 1, 2022				Proposed Rates Effective October 1, 2022				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Delivery Services (n) = (j) / (e)	Supply Services (o) = (k) / (e)	GET (p) = (l) / (e)	Total (q) = (m) / (e)
200	200	40,000	$4,242.55	$5,101.20	$389.32	$9,733.07	$4,233.75	$5,101.20	$388.96	$9,723.91	($8.80)	$0.00	($0.36)	($9.16)	-0.1%	0.0%	0.0%	-0.1%
750	200	150,000	$15,871.75	$19,129.50	$1,458.39	$36,459.64	$15,838.75	$19,129.50	$1,457.01	$36,425.26	($33.00)	$0.00	($1.38)	($34.38)	-0.1%	0.0%	0.0%	-0.1%
1,000	200	200,000	$21,157.75	$25,506.00	$1,944.32	$48,608.07	$21,113.75	$25,506.00	$1,942.49	$48,562.24	($44.00)	$0.00	($1.83)	($45.83)	-0.1%	0.0%	0.0%	-0.1%
1,500	200	300,000	$31,729.75	$38,259.00	$2,916.20	$72,904.95	$31,663.75	$38,259.00	$2,913.45	$72,836.20	($66.00)	$0.00	($2.75)	($68.75)	-0.1%	0.0%	0.0%	-0.1%
2,500	200	500,000	$52,873.75	$63,765.00	$4,859.95	$121,498.70	$52,763.75	$63,765.00	$4,855.36	$121,384.11	($110.00)	$0.00	($4.59)	($114.59)	-0.1%	0.0%	0.0%	-0.1%
5,000	200	1,000,000	$105,733.75	$127,530.00	$9,719.32	$242,983.07	$105,513.75	$127,530.00	$9,710.16	$242,753.91	($220.00)	$0.00	($9.16)	($229.16)	-0.1%	0.0%	0.0%	-0.1%
7,500	200	1,500,000	$158,593.75	$191,295.00	$14,578.70	$364,467.45	$158,263.75	$191,295.00	$14,564.95	$364,123.70	($330.00)	$0.00	($13.75)	($343.75)	-0.1%	0.0%	0.0%	-0.1%
10,000	200	2,000,000	$211,453.75	$255,060.00	$19,438.07	$485,951.82	$211,013.75	$255,060.00	$19,419.74	$485,493.49	($440.00)	$0.00	($18.33)	($458.33)	-0.1%	0.0%	0.0%	-0.1%
20,000	200	4,000,000	$422,893.75	$510,120.00	$38,875.58	$971,889.33	$422,013.75	$510,120.00	$38,838.91	$970,972.66	($880.00)	$0.00	($36.67)	($916.67)	-0.1%	0.0%	0.0%	-0.1%
200	300	60,000	$5,151.95	$7,651.80	$533.49	$13,337.24	$5,138.75	$7,651.80	$532.94	$13,323.49	($13.20)	$0.00	($0.55)	($13.75)	-0.1%	0.0%	0.0%	-0.1%
750	300	225,000	$19,282.00	$28,694.25	$1,999.01	$49,975.26	$19,232.50	$28,694.25	$1,996.95	$49,923.70	($49.50)	$0.00	($2.06)	($51.56)	-0.1%	0.0%	0.0%	-0.1%
1,000	300	300,000	$25,704.75	$38,259.00	$2,665.16	$66,628.91	$25,638.75	$38,259.00	$2,662.41	$66,560.16	($66.00)	$0.00	($2.75)	($68.75)	-0.1%	0.0%	0.0%	-0.1%
1,500	300	450,000	$38,550.25	$57,388.50	$3,997.45	$99,936.20	$38,451.25	$57,388.50	$3,993.32	$99,833.07	($99.00)	$0.00	($4.13)	($103.13)	-0.1%	0.0%	0.0%	-0.1%
2,500	300	750,000	$64,241.25	$95,647.50	$6,662.03	$166,550.78	$64,076.25	$95,647.50	$6,655.16	$166,378.91	($165.00)	$0.00	($6.87)	($171.87)	-0.1%	0.0%	0.0%	-0.1%
5,000	300	1,500,000	$128,468.75	$191,295.00	$13,323.49	$333,087.24	$128,138.75	$191,295.00	$13,309.74	$332,743.49	($330.00)	$0.00	($13.75)	($343.75)	-0.1%	0.0%	0.0%	-0.1%
7,500	300	2,250,000	$192,696.25	$286,942.50	$19,984.95	$499,623.70	$192,201.25	$286,942.50	$19,964.32	$499,108.07	($495.00)	$0.00	($20.63)	($515.63)	-0.1%	0.0%	0.0%	-0.1%
10,000	300	3,000,000	$256,923.75	$382,590.00	$26,646.41	$666,160.16	$256,263.75	$382,590.00	$26,618.91	$665,472.66	($660.00)	$0.00	($27.50)	($687.50)	-0.1%	0.0%	0.0%	-0.1%
20,000	300	6,000,000	$513,833.75	$765,180.00	$53,292.24	$1,332,305.99	$512,513.75	$765,180.00	$53,237.24	$1,330,930.99	($1,320.00)	$0.00	($55.00)	($1,375.00)	-0.1%	0.0%	0.0%	-0.1%
200	400	80,000	$6,061.35	$10,202.40	$677.66	$16,941.41	$6,043.75	$10,202.40	$676.92	$16,923.07	($17.60)	$0.00	($0.74)	($18.34)	-0.1%	0.0%	0.0%	-0.1%
750	400	300,000	$22,692.25	$38,259.00	$2,539.64	$63,490.89	$22,626.25	$38,259.00	$2,536.89	$63,422.14	($66.00)	$0.00	($2.75)	($68.75)	-0.1%	0.0%	0.0%	-0.1%
1,000	400	400,000	$30,251.75	$51,012.00	$3,385.99	$84,649.74	$30,163.75	$51,012.00	$3,382.32	$84,558.07	($88.00)	$0.00	($3.67)	($91.67)	-0.1%	0.0%	0.0%	-0.1%
1,500	400	600,000	$45,370.75	$76,518.00	$5,078.70	$126,967.45	$45,238.75	$76,518.00	$5,073.20	$126,829.95	($132.00)	$0.00	($5.50)	($137.50)	-0.1%	0.0%	0.0%	-0.1%
2,500	400	1,000,000	$75,608.75	$127,530.00	$8,464.12	$211,602.87	$75,388.75	$127,530.00	$8,454.95	$211,373.70	($220.00)	$0.00	($9.17)	($229.17)	-0.1%	0.0%	0.0%	-0.1%
5,000	400	2,000,000	$151,203.75	$255,060.00	$16,927.66	$423,191.41	$150,763.75	$255,060.00	$16,909.32	$422,733.07	($440.00)	$0.00	($18.34)	($458.34)	-0.1%	0.0%	0.0%	-0.1%
7,500	400	3,000,000	$226,798.75	$382,590.00	$25,391.20	$634,779.95	$226,138.75	$382,590.00	$25,363.70	$634,092.45	($660.00)	$0.00	($27.50)	($687.50)	-0.1%	0.0%	0.0%	-0.1%
10,000	400	4,000,000	$302,393.75	$510,120.00	$33,854.74	$846,368.49	$301,513.75	$510,120.00	$33,818.08	$845,451.83	($880.00)	$0.00	($36.66)	($916.66)	-0.1%	0.0%	0.0%	-0.1%
20,000	400	8,000,000	$604,773.75	###########	$67,708.91	$1,692,722.66	$603,013.75	###########	$67,635.58	$1,690,889.33	($1,760.00)	$0.00	($73.33)	($1,833.33)	-0.1%	0.0%	0.0%	-0.1%
200	500	100,000	$6,970.75	$12,753.00	$821.82	$20,545.57	$6,948.75	$12,753.00	$820.91	$20,522.66	($22.00)	$0.00	($0.91)	($22.91)	-0.1%	0.0%	0.0%	-0.1%
750	500	375,000	$26,102.50	$47,823.75	$3,080.26	$77,006.51	$26,020.00	$47,823.75	$3,076.82	$76,920.57	($82.50)	$0.00	($3.44)	($85.94)	-0.1%	0.0%	0.0%	-0.1%
1,000	500	500,000	$34,798.75	$63,765.00	$4,106.82	$102,670.57	$34,688.75	$63,765.00	$4,102.24	$102,555.99	($110.00)	$0.00	($4.58)	($114.58)	-0.1%	0.0%	0.0%	-0.1%
1,500	500	750,000	$52,191.25	$95,647.50	$6,159.95	$153,998.70	$52,026.25	$95,647.50	$6,153.07	$153,826.82	($165.00)	$0.00	($6.88)	($171.88)	-0.1%	0.0%	0.0%	-0.1%
2,500	500	1,250,000	$86,976.25	$159,412.50	$10,266.20	$256,654.95	$86,701.25	$159,412.50	$10,254.74	$256,368.49	($275.00)	$0.00	($11.46)	($286.46)	-0.1%	0.0%	0.0%	-0.1%
5,000	500	2,500,000	$173,938.75	$318,825.00	$20,531.82	$513,295.57	$173,388.75	$318,825.00	$20,508.91	$512,722.66	($550.00)	$0.00	($22.91)	($572.91)	-0.1%	0.0%	0.0%	-0.1%
7,500	500	3,750,000	$260,901.25	$478,237.50	$30,797.45	$769,936.20	$260,076.25	$478,237.50	$30,763.08	$769,076.83	($825.00)	$0.00	($34.37)	($859.37)	-0.1%	0.0%	0.0%	-0.1%
10,000	500	5,000,000	$347,863.75	$637,650.00	$41,063.08	$1,026,576.83	$346,763.75	$637,650.00	$41,017.24	$1,025,430.99	($1,100.00)	$0.00	($45.84)	($1,145.84)	-0.1%	0.0%	0.0%	-0.1%
20,000	500	10,000,000	$695,713.75	###########	$82,125.58	$2,053,139.33	$693,513.75	###########	$82,033.91	$2,050,847.66	($2,200.00)	$0.00	($91.67)	($2,291.67)	-0.1%	0.0%	0.0%	-0.1%
200	600	120,000	$7,880.15	$15,303.60	$965.99	$24,149.74	$7,853.75	$15,303.60	$964.89	$24,122.24	($26.40)	$0.00	($1.10)	($27.50)	-0.1%	0.0%	0.0%	-0.1%
750	600	450,000	$29,512.75	$57,388.50	$3,620.89	$90,522.14	$29,413.75	$57,388.50	$3,616.76	$90,419.01	($99.00)	$0.00	($4.13)	($103.13)	-0.1%	0.0%	0.0%	-0.1%
1,000	600	600,000	$39,345.75	$76,518.00	$4,827.66	$120,691.41	$39,213.75	$76,518.00	$4,822.16	$120,553.91	($132.00)	$0.00	($5.50)	($137.50)	-0.1%	0.0%	0.0%	-0.1%
1,500	600	900,000	$59,011.75	$114,777.00	$7,241.20	$181,029.95	$58,813.75	$114,777.00	$7,232.95	$180,823.70	($198.00)	$0.00	($8.25)	($206.25)	-0.1%	0.0%	0.0%	-0.1%
2,500	600	1,500,000	$98,343.75	$191,295.00	$12,068.28	$301,707.03	$98,013.75	$191,295.00	$12,054.53	$301,363.28	($330.00)	$0.00	($13.75)	($343.75)	-0.1%	0.0%	0.0%	-0.1%
5,000	600	3,000,000	$196,673.75	$382,590.00	$24,135.99	$603,399.74	$196,013.75	$382,590.00	$24,108.49	$602,712.24	($660.00)	$0.00	($27.50)	($687.50)	-0.1%	0.0%	0.0%	-0.1%
7,500	600	4,500,000	$295,003.75	$573,885.00	$36,203.70	$905,092.45	$294,013.75	$573,885.00	$36,162.45	$904,061.20	($990.00)	$0.00	($41.25)	($1,031.25)	-0.1%	0.0%	0.0%	-0.1%
10,000	600	6,000,000	$393,333.75	$765,180.00	$48,271.41	$1,206,785.16	$392,013.75	$765,180.00	$48,216.41	$1,205,410.16	($1,320.00)	$0.00	($55.00)	($1,375.00)	-0.1%	0.0%	0.0%	-0.1%
20,000	600	12,000,000	$786,653.75	###########	$96,542.25	$2,413,556.00	$784,013.75	###########	$96,432.25	$2,410,806.00	($2,640.00)	$0.00	($110.00)	($2,750.00)	-0.1%	0.0%	0.0%	-0.1%

		Rates Effective July 1, 2022 (r)	Proposed Rates Effective October 1, 2022 (s)	Line Item on Bill
(1)	Distribution Customer Charge	$1,100.00	$1,100.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.79	$0.79	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$308.96	$308.96	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 200kW)	$5.30	$5.30	Distribution Demand Charge
(5)	CapEx Factor Demand Charge (per kW > 200kW)	$1.68	$1.68	
(6)	Distribution Charge (per kWh)	$0.00430	$0.00430	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00094	$0.00094	
(8)	Operating & Maintenance Expense Reconciliation Factor	($0.00010)	$0.00000	
(9)	CapEx Reconciliation Factor	($0.00013)	($0.00045)	
(10)	Revenue Decoupling Adjustment Factor	($0.00003)	($0.00003)	
(11)	Pension Adjustment Factor	($0.00006)	($0.00006)	
(12)	Storm Fund Replenishment Factor	$0.00788	$0.00788	
(13)	Arrearage Management Adjustment Factor	$0.00007	$0.00007	
(14)	Performance Incentive Factor	$0.00012	$0.00012	
(15)	Low Income Discount Recovery Factor	$0.00238	$0.00238	
(16)	Long-term Contracting for Renewable Energy Charge	($0.00131)	($0.00131)	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.00488	$0.00488	
(18)	Transmission Demand Charge	$5.07	$5.07	Transmission Demand Charge
(19)	Base Transmission Charge	$0.01442	$0.01442	Transmission Adjustment
(20)	Transmission Adjustment Factor	($0.00093)	($0.00093)	
(21)	Transmission Uncollectible Factor	$0.00034	$0.00034	
(22)	Base Transition Charge	$0.00000	$0.00000	Transition Charge
(23)	Transition Adjustment	$0.00018	$0.00018	
(24)	Energy Efficiency Program Charge	$0.01252	$0.01252	Energy Efficiency Programs
(25)	Last Resort Service Base Charge	$0.11389	$0.11389	Supply Services Energy Charge
(26)	LRS Adjustment Factor	$0.00375	$0.00375	
(27)	LRS Adminstrative Cost Adjustment Factor	$0.00268	$0.00268	
(28)	Renewable Energy Standard Charge	$0.00721	$0.00721	
	Line Item on Bill			
(29)	Customer Charge	$1,100.00	$1,100.00	
(30)	LIHEAP Enhancement Charge	$0.79	$0.79	
(31)	RE Growth Program	$308.96	$308.96	
(32)	Transmission Adjustment	$0.01383	$0.01383	
(33)	Distribution Energy Charge	$0.01537	$0.01515	
(34)	Distribution Demand Charge	$6.98	$6.98	
(35)	Transmission Demand Charge	$5.07	$5.07	
(34)	Transition Charge	$0.00018	$0.00018	
(35)	Energy Efficiency Programs	$0.01252	$0.01252	
(36)	Renewable Energy Distribution Charge	$0.00357	$0.00357	
(37)	Supply Services Energy Charge	$0.12753	$0.12753	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022
Column (s): Line (8) per Attachment PRB-3, Page 1, Line (7). Line (9) per Attachment PRB-2, Page 1, Line (10).All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2022, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2022