National Grid

The Narragansett Electric Company

FY 2021 Electric Infrastructure, Safety and Reliability Plan

Annual Reconciliation

July 30, 2021

Docket No. 4995

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

July 30, 2021

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4995 - Fiscal Year 2021 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Filing

Dear Ms. Massaro:

On behalf of National Grid,[1] relating to the Company's Fiscal Year ("FY") 2021 Electric Infrastructure, Safety, and Reliability ("ISR") Plan, I have enclosed for filing with the Rhode Island Public Utilities Commission ("PUC") the Company's Electric ISR Reconciliation Filing.[2] Pursuant to the approved ISR Plan and the ISR Provision, RIPUC No. 2199, after the end of the ISR Plan year, which runs from April 1 through March 31, the Company must file annually, by August 1 of each year, the proposed CapEx Reconciling Factors and Operation and Maintenance ("O&M") Reconciling Factor that will become effective for the 12 months beginning October 1. The CapEx Reconciling Factors recover or refund the difference between the reconciliation of actual billed revenue generated from the CapEx Factors and the actual revenue requirement based on actual cumulative ISR capital investment for the applicable plan year. Similarly, the annual O&M Reconciling Factor recovers or refunds the difference between the reconciliation of actual billed revenue from the O&M Factor and actual Inspection and Maintenance ("I&M") program expense and actual Vegetation Management ("VM") program expense for the ISR Plan year. Additionally, on August 1, the Company must report on the prior fiscal year's ISR Plan activities and include descriptions of deviations from the original plans approved by the PUC.

This filing provides the actual discretionary and non-discretionary capital investment spending and the actual VM and I&M expenses for the period April 1, 2020 to March 31, 2021. As explained in this filing, the actual capital plant-in-service is compared to the budgeted amounts for these categories, as approved by the PUC in Docket No. 4995. The plant-in-service investment and O&M expenses for VM and I&M are then used in the calculation of the revenue requirement for the annual reconciliation of investment and expenses for the fiscal year. This revenue requirement is then compared to actual revenue billed, and any difference forms the basis for the proposed Electric ISR Plan reconciliation factors for effect October 1, 2021. This filing also includes details

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).
[2] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by ten hard copies filed with the Clerk within 24 hours of the electronic filing.

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on the Company's actual discretionary and non-discretionary capital investment spending by category during FY 2021. Finally, this filing includes a summary of the Company's Reliability Performance through December 31, 2020.

The pre-filed direct testimonies of Patricia Easterly, Melissa A. Little, and Daniel Gallagher are enclosed with this filing. Ms. Easterly presents the Company's FY 2021 Electric ISR Plan Reconciliation Filing related to the FY 2021 Electric ISR Plan, which the PUC approved in this docket. Ms. Little's testimony describes the calculation of the revenue requirement based on the capital plant-in-service and the total annual actual VM and I&M expenses for the fiscal year. Ms. Little's testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. As explained in Ms. Little's testimony, for the FY 2021 Electric ISR reconciliation, the Company has an updated revenue requirement of $30,717,902. The revenue requirement is based on actual FY 2021 O&M programs, the actual capital investment levels for each of FY 2018 through FY 2021 incremental to the level of investment assumed in base distribution rates under Docket No. 4770, and actual tax deductibility percentages for FY 2020 capital additions.

Mr. Gallagher describes the reconciliation of the final FY 2021 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 reconciliation reflects CapEx revenue billed through the CapEx Factors and O&M revenue billed through the O&M Factor during the period of April 1, 2020 through March 31, 2021. The impact of the proposed CapEx Reconciling Factors and the proposed O&M Reconciling Factor on a typical residential customer receiving Standard Offer Service and using 500 kWhs per month is a decrease of $0.90, or 0.8%, from $108.92 to $108.02 per month.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket 4995 Service List
Leo Wold, Esq.
John Bell, Division

PRE-FILED DIRECT TESTIMONY

OF

PATRICIA C. EASTERLY

July 30, 2021

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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 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am employed by National Grid USA Service Company, Inc. (NGSC) as Director –New England Operations and Regulatory Delivery. In my position, I am responsible for regulatory compliance related to electric distribution and, in particular, for capital expenditures for The Narragansett Electric Company d/b/a National Grid (the Company).

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, Director for Finance Performance Management program and Director – New England Electric Performance and Strategy. In April of 2021, I assumed my current position as Director of New England Electric Operations and Regulatory Delivery.

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 2022 Electric Infrastructure, Safety and Reliability (ISR) 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. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company's FY 2021 Annual Reconciliation filing related to the FY 2021 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, 2020 to March 31, 2021. As described in Ms. Melissa Little's testimony in this filing, this plant-in-service investment and the O&M expenses are used to calculate the FY 2021 Electric ISR Plan revenue requirement. As explained in Mr. Gallagher's 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 2021. Specific details by category for the FY 2021 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

Q. Please provide an overview of the plant-in-service for FY 2021.

A. As shown in Table 2 of Attachment PCE-1, in FY 2021, the Company's plant-in-service investment was $116.5 million. This amount was approximately $6.0 million over the planned amount of $110.5 million. Non-Discretionary plant additions totaling $36.4 million were placed in service, which was $2.9 million over the planned amount of $33.5 million. This variance was due to more plant additions related to failed assets, storms, and customer-driven work offset by billings associated with the joint owned pole agreement and RI Department of Transportation (RIDOT) projects. Discretionary plant additions totaling $80.0 million were placed in service, which was $3.1 million over the planned amount of $76.9 million. Lower System Capacity and Performance plant additions were primarily driven by less Strategic DER Enabling Investments put into service than targeted. Asset Condition plant additions were greater than target due to the following programs and projects: Underground Residential Distribution (URD) and Underground Cable projects, Southeast Substation, the Cottage Street Retirement project and Apponaug Substation short term work. Actual plant additions were less than target for the Dyer Street and Providence Area Study projects due to project delays. As shown in Table 3 of Attachment PCE-1, in FY 2021, the associated cost of removal (COR) was $11.3 million which was under-budget by $0.4 million from the FY 2021 target of $11.7 million. These totals resulted in a net Electric ISR Plan investment of $127.8 million, which was $5.6 million over the Company's combined plant-in-service and COR planned amount of $122.2 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 2021 for the Electric ISR Plan.

A. As shown in Table 4 of Attachment PCE-1, for FY 2021, the Company spent $100.6 million for capital investment under the Electric ISR Plan. This amount was $3.1 million under the annual approved budget of $103.8 million. Non-discretionary capital spending included underspending on Strategic DER Enabling Devices and Meters and billings greater than budgeted for RI Department of Transportation projects and the joint-owned pole agreement. This was partially offset by spending related to Distributed Generation projects, as the Company transitions to a new process for recording customer contributions and activity associated with major storm work.

For FY 2021, capital spending in the Discretionary sub-category (excluding Southeast Substation) was $46.2 million, which was $8.6 million under the annual approved budget of $54.8 million. This was driven primarily by underspending on major projects including Dyer Street and East Providence substations and Providence Area Study and Aquidneck Island projects. This was partially offset by underground cable programs and spending on projects rolling over from the previous year. Capital spending on the Southeast Substation project, which was managed as a separate Discretionary sub-category, was $13.0 million, which was $2.9 million over the annual approved budget of $10.1 million.

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

V. O&M Spending

Q. Please summarize the Company's actual O&M spending for the FY 2021 Electric ISR Plan.

A. As shown in Table 10 of Attachment PCE-1, for FY 2021, the Company's vegetation management ("VM") O&M spending was $10.7 million, which was slightly over-budget by $0.1 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 $0.9 million, which was $0.6 million under the approved O&M budget of $1.5 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 2020.

A. Section VI. of Attachment PCE-1 includes the Company's Reliability Performance for calendar year 2020 (CY 2020). The Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2020, with SAIFI of 0.945 against a target of 1.05, and SAIDI of 69.1 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured excluding major event days.[1]

[1] A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (6.03 minutes for CY 2020). 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. Does this conclude your testimony?

A. Yes.

Attachment PCE-1

FY 2021 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation Filing

FY 2021 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 National Grid (the Company) submits this Annual Reconciliation Filing for the FY 2021 Electric Infrastructure, Safety and Reliability Plan approved by the Rhode Island Public Utilities Commission (PUC) in Docket No. 4995. This filing provides the actual capital investment, vegetation management (VM) and other operation and maintenance (O&M) spending for the period April 1, 2020 to March 31, 2021. 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, 2020. Table 1 summarizes the FY 2021 program.

Table 1
FY 2021 ISR Activity

FY 2021 *in millions $*	**Target / Budget**	**Actuals**	**Variance Over / (Under)**
Plant in Service Additions - Non-discretionary	$33.5	$36.4	$2.9
Plant in Service Additions - Discretionary	$76.9	$80.0	$3.1
Plant in Service Additions	**$110.5**	**$116.5**	**$6.0**
Cost of Removal Spending - Non-discretionary	$4.3	$6.2	$1.9
Cost of Removal Spending - Discretionary	$7.4	$5.1	($2.3)
Cost of Removal Spending	**$11.7**	**$11.3**	**($0.4)**
Capital Spending - Non-discretionary	$38.9	$41.5	$2.6
Capital Spending - Discretionary	$64.8	$59.1	($5.7)
Capital Spending	**$103.8**	**$100.6**	**($3.1)**
Vegetation Management Spending	$10.6	$10.7	$0.1
I&M and Other O&M Spending	$1.5	$0.8	($0.6)
O&M Spending	**$12.1**	**$11.5**	**($0.6)**

This filing includes testimony from Ms. Little and Mr. Gallagher. Ms. Little's 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. Ms. Little's testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. As shown in Ms. Little's testimony, for the FY 2021 filing, the Company has an updated revenue requirement of $30.7 million.

Mr. Gallagher's testimony provides a description of the reconciliation of the final actual FY 2021 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 $0.90, or approximately 0.8% from $108.92 to $108.02.

I. FY 2021 Capital for Plant Investment Placed in Service

As shown in Table 2 below, in FY 2021, $116.5 million of plant additions were placed in service, which was $6.0 million over the target amount of $110.5 million. Non-discretionary plant additions totaling $36.4 million were placed in service, which was $2.9 million over the target of $33.5 million. This increase was due to more plant additions associated with failed assets and storms, partially offset by billings associated with the joint owned pole agreement. Discretionary plant additions totaling $80.0 million were placed in service, which was $3.1 million over the planned amount of $76.9 million. Plant additions totaling $14.4 million related to the Southeast Substation project were put into service as compared with a planned amount of $12.6 million. Additional Asset Condition plant placed in service include Underground Residential Distribution (URD) and underground cable projects, Cottage Street and Apponaug Substation projects, as well as completion of the Distribution Secondary Network Arc program. Lower System Capacity & Performance plant additions were driven primarily by lower Strategic DER Enabling devices and lower EMS and VVO plant than originally estimated.

Table 2
Plant Additions by Category

	Target	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$21,210,000	$16,761,073	($4,448,927)
Damage Failure	$12,335,000	$19,684,473	$7,349,473
Non-Discretionary Sub-total	*$33,545,000*	*$36,445,546*	*$2,900,546*
Asset Condition	$38,948,000	$46,730,370	$7,782,370
Non-Infrastructure	$566,000	$196,585	($369,415)
System Capacity & Performance	$37,435,000	$33,114,299	($4,320,701)
Discretionary Sub-total	*$76,949,000*	*$80,041,254*	*$3,092,254*
Total Capital Investment in System	**$110,494,000**	**$116,486,799**	**$5,992,799**

The variances shown in Table 2 reflect the timing of when plant investment 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 they can be 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 2021, which was $11.3 million, $0.4 million under the forecast of $11.7 million. Non-discretionary COR spending was $6.2 million, which was $1.9 million over the planned amount of $4.3 million. COR associated with Discretionary projects totaled $5.1 million, which was $2.3 million over the annual planned amount of $7.4 million.

Table 3
COR by Category

	Target	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$2,243,000	$3,731,559	$1,488,559
Damage Failure	$2,047,000	$2,446,438	$399,438
Non-Discretionary Sub-total	*$4,290,000*	*$6,177,996*	*$1,887,996*
Asset Condition	$5,381,000	$3,257,667	($2,123,333)
Non-Infrastructure	$8,000	$629	($7,371)
System Capacity & Performance	$2,021,000	$1,862,911	($158,089)
Discretionary Sub-total	*$7,410,000*	*$5,121,207*	*($2,288,793)*
Total Capital Investment in System	**$11,700,000**	**$11,299,204**	**($400,796)**

II. FY 2021 Capital Spending Summary

As shown in Table 4 below, capital spending for FY 2021 totaled $100.6 million, which was $3.1 million under the FY 2021 budget of $103.8 million.

Table 4
Capital Spending by Category

	Budget	Actuals	Variance Over / (Under)
Customer Request/Public Requirement	$26,540,000	$21,989,900	($4,550,100)
Damage Failure	$12,365,000	$19,490,705	$7,125,705
Non-Discretionary Sub-total	*$38,905,000*	*$41,480,605*	*$2,575,605*
Asset Condition	$31,040,000	$28,865,121	($2,174,879)
Non-Infrastructure	$580,000	($57,278)	($637,278)
System Capacity & Performance	$23,145,000	$17,387,358	($5,757,642)
Discretionary Sub-total (without Southeast Substation)	*$54,765,000*	*$46,195,201*	*($8,569,799)*
Southeast Substation Project	$10,080,000	$12,951,379	$2,871,379
Discretionary Sub-total	*$64,845,000*	*$59,146,581*	*($5,698,419)*
Total Capital Investment in System	**$103,750,000**	**$100,627,186**	**($3,122,814)**

III. FY 2021 Capital Spending by Key Driver Category

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

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

Capital spending for FY 2021 in the Customer Request/Public Requirement category was approximately $22.0 million, which was $4.6 million under the FY 2021 budget of $26.5 million. The major drivers of this variance are:

- Activity associated with a joint-owned pole agreement was the primary driver for the $1.8 million variance in the New Business-Residential spending category. Billings under the agreement totaled $4.6 million which exceeded the budget of $1.4 million resulting in additional credits applied to this category. Remaining activity under the blanket project and on specific projects was $1.5 million over the $5.7 million budgeted.
- Spending in the New Business-Commercial category was $1.2 million under budget for the year. This variance was driven by underspending in both the blanket project and specific projects during the year.

- Spending in the Public Requirements category was $4.1 million under budget for the year. This variance was driven by Rhode Island Department of Transportation billings of $5.3 million included in the Public Requirements spending category.
- The projects associated with Meter Purchases and Installations are under budget by $1.4 million for FY 2021. Spending was less than the amount budgeted due to the purchase of fewer meters and decreased field activity for non-essential work. Some meter change work and installations requiring customer facing interaction were not done due to COVID-19 work restrictions.
- A minimal amount of spending took place for engineering to determine needs and scope at Chopmist and Hopkins Hill substations. This resulted in an underspending of $2.0 million in the Strategic DER Enabling Devices category.
- Billings for work that will take place in FY 2022 reduced the Third-Party Attachments actual spending causing the category to be under budget by $0.8 million at fiscal year-end.
- Activity in the Distributed Generation category was $6.6 million over budget primarily due to the transition to the new process for recording Contributions in Aid of Construction (CIAC). Substantial progress was made to record CIACs at the project work order level when work is performed instead of when the CIAC is received. Implementation of this process will continue into FY 2022. Once the process has been fully implemented, the Company expects that the net capital activity for any fiscal year will be minimal.

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	$200,000	($629,165)	($829,165)
	Distributed Generation	$1,000,000	$7,614,870	$6,614,870
	Land and Land Rights	$385,000	$404,412	$19,412
	Meters – Distribution	$2,995,000	$1,604,705	($1,390,295)
	New Business – Commercial	$8,405,000	$7,158,031	($1,246,969)
	New Business – Residential	$4,370,000	$2,536,043	($1,833,957)
	Outdoor Lighting – Capital	$315,000	$508,919	$193,919
	Public & Regulatory Requirement	$2,670,000	($1,409,654)	($4,079,654)
	Transformers & Related Equipment	$4,200,000	$4,199,427	($573)
	Strategic DER Investments	$2,000,000	$2,314	($1,997,686)
	Customer Request/Public Requirement Spending	**$26,540,000**	**$21,989,900**	**($4,550,100)**

b. Damage/Failure

Capital spending in the Damage/Failure category was $19.5 million, which was $7.1 million over the FY 2021 budget of $12.4 million. This variance was driven primarily by the following:

- Spending on major storms totaled $7.8 million, which is $6.1 million over the budget of $1.7 million. There were 12 major storm events in FY 2021 as compared with three major storms in FY 2020.
- The remaining spending in the Damage/Failure is over budget by $1.0 million. The Company began adopting the new process of categorizing only work related to failed assets in the Non-discretionary portfolio during FY 2021. All other work is categorized in the Asset Replacement category of the Discretionary portfolio. During the preparation of the FY 2021 budget, it was estimated that the impact of this new process would reduce Damage/Failure spending by $2.0 million from the FY 2020 level. Asset Replacement and Inspection & Maintenance (I&M) budgets were each increased $1 million over FY 2020 budgets. The transition to the new process progressed throughout the fiscal year and the Company performed a monthly review of spending to ensure appropriate categorization. Monthly review of Damage/Failure work will continue in FY 2022.

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	$10,640,000	$11,663,467	$1,023,467
	Major Storms	$1,725,000	$7,827,238	$6,102,238
	Damage/Failure Spending	**$12,365,000**	**$19,490,705**	**$7,125,705**

2. Discretionary Spending

a. Asset Condition (without Southeast Substation)

Capital spending in the Asset Condition category excluding the Southeast Substation projects was $28.9 million, which was $2.2 million under the FY 2021 budget of $31.0 million. The following projects and programs drove the under-spending:

- Capital spending on Dyer Street substation was $3.2 million which was $3.9 million under the budget of $7.2 million. This project was paused in FY 2020 due to higher cost estimates than expected. The Company performed a revised option analysis which resulted in an updated project at reduced costs and created spending shifts from the first half of FY 2021 to the last half of FY 2021 and into FY 2022.
- Capital spending on the Providence Area Study projects (Admiral Street projects) was $2.6 million which was $1.6 million under the budget of $4.2 million primarily due to project delays as well as capital efficiencies that were secured related to the use of an existing transformer rather than purchasing a new transformer.
- Capital spending on URD projects was $0.9 million greater than budget due to several individual drivers. These drivers included drivers such as site restoration work requiring curb to curb paving, increased labor costs to minimize outage durations to accommodate remote working during COVID, and increased site costs due to underground conditions that were not known when project estimates were made. As these variances became apparent, all URD work was stopped in September and some projects planned for FY 2021 were deferred to FY 2022.
- Underground Cable Replacement program spending is $0.6 million over the $3.8 million budget primarily due to coordination of work in critical downtown Providence areas where work time constraints caused work to be performed at night at higher rates.

- The Apponaug Substation short term work, which included retirement of the 23kV and installing relayed reclosers for transformer protection and was included in the Central Rhode Island East Area Study, was completed and put in service during FY 2021. Capital spending was $1.2 million, which was $0.9 million more than the amount budgeted in FY 2021 because at the time the FY21 budget was estimated, the project was $0.6 million under budget and more work was expected to be completed in FY20.
- Two additional projects were completed during FY 2021 that were begun in prior years. Capital spending on Kent County Breaker Replacement project was $0.5 million and capital spending on a Distribution Secondary Network Arc project was $0.8 million. Both projects were expected to be completed in previous years and lagged into FY 2021 after the FY 2021 budget was set. These projects were placed into service by the end of the fiscal year.
- The Asset Replacement Blanket and I&M budgets were each increased in FY 2021 over the FY 2020 levels by $1 million (or $2 million combined) to estimate for the change in the process for classification of failed assets, as discussed above. The Asset Replacement blanket was $0.3 million over the FY 2021 budget of $4.5 million and the I&M program was $0.9 million under the FY 2021 budget of $2.9 million. Refer to the Damage/Failure section of this report for additional information on the changes to the classification of failed assets and the Company's continuing monthly review of Damage/Failure work.

b. <u>Asset Condition – Southeast Substation</u>

Capital spending on the Southeast Substation Replacement project was $13.0 million, which was $2.9 million over the FY 2021 budget of $10.1 million. This was due in part to a carryover of work delayed in FY 2020 and increased costs. The substation portion of this project is substantially complete and went into service in March 2021. The remaining substation work planned for FY 2022 is site civil work. The distribution line portion of this project is expected to be completed in FY 2022. In total, the Company currently expects capital spending to be $22.2 million for this project as compared with the estimate when sanctioned of $21.1 million. The difference of $1.8 million is primarily due to field conditions, requiring environmental management of an additional volume of soil, and additional resources, such as crane and other equipment rentals, to manage construction site congestion.

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	$28,140,000	$26,137,056	($2,002,944)
	Asset Replacement – Southeast	$10,080,000	$12,951,379	$2,871,379
	Asset Replacement - I&M	$2,900,000	$1,970,060	($929,940)
	Safety & Other	$0	$758,005	$758,005
	Asset Condition Spending	**$41,120,000**	**$41,816,500**	**$696,500**

c. Non-Infrastructure

Capital spending for the Non-Infrastructure category was $(0.1) million, which was $0.6 million under the FY 2021 budget of $0.6 million.

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	($366,137)	($366,137)
	General Equipment	$330,000	$206,070	($123,930)
	Telecommunications	$250,000	$102,789	($147,211)
	Non-Infrastructure Spending	**$580,000**	**($57,278)**	**($637,278)**

d. System Capacity & Performance

Capital spending for FY 2021 for the System Capacity and Performance category was $17.4 million, which was $5.8 million under the FY 2021 budget of $23.2 million. This variance was driven primarily by the following projects:

- Capital spending on the Aquidneck Island project was $4.3 million under the budget of $13.5 million. Reductions in spending relate to COVID-19 work requirements shifting some construction costs into FY 2022, as well as the removal of contingencies once it was determined that a required outage could be scheduled during FY 2021.

- Capital spending on New Lafayette substation project was $0.5 million over the FY 2021 budget of $0.4 million as a result of advancing civil work to enable efficiencies by coordinating with a Distributed Generation project taking place on the same site.
- Capital spending on the East Providence substation was $1.3 million under the budget of $1.6 million due to project delays.
- Capital spending for the EMS Expansion program was $0.7 million under the budget of $1.0 million. Underspending was partially a result of pausing work at sites to allow for alignment with area studies.
- The Company spent $1.9 million for its 3V0 program and Strategic DER Advancement projects against a budget of $2.2 million in FY 2021. This was primarily driven by the purchase of four mobile 3V0 units that came in under the original estimate by $0.6 million.
- During FY 2021, the Company spent $0.3 million on COVID-19 related work and included the spending as Discretionary. This work included small-scale solutions such as fuse replacements, feeder balancing, and upgrading equipment such as load break switches and step-down transformers, to larger sizes.

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	$15,410,000	$10,986,876	($4,423,124)
	Reliability	$7,735,000	$6,400,482	($1,334,518)
	System Capacity & Performance Spending	**$23,145,000**	**$17,387,358**	**($5,757,642)**

For additional information on specific large project variances, please see Attachment E to the Company's FY 2021 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2021 (Docket 4995) filed with the PUC on May 17, 2021. A copy of this report is attached as Attachment 1.

IV. FY 2021 Vegetation Management (VM)

For FY 2021, the Company completed 1,215 miles of distribution cycle pruning at a cost of $10.7 million. The Company completed 100% of its work plan for FY 2021. Table 10 below provides the spending components in the VM category.

Table 10
Vegetation Management O&M Spending

	Budget	Actuals	Variance Over / (Under)
Cycle Pruning (Base)	$6,100,000	$5,967,732	($132,268)
Hazard Tree	$1,750,000	$1,653,165	($96,835)
Sub-T (on & off road)	$550,000	$397,297	($152,703)
Police/Flagman Details	$775,000	$767,794	($7,206)
Core Crew (all other activities)	$1,425,000	$1,899,653	$474,653
Total VM O&M Spending	**$10,600,000**	**$10,685,641**	**$85,641**

V. FY 2021 Other Operations and Maintenance (O&M)

For FY 2021, the Company completed 100% of its annual goal of 48,631 overhead structures inspected with an associated spend of $0.5 million. Table 11 below provides the total FY 2021 spending for all components in the Other O&M category.

Table 11
Other O&M Spending

	Budget	Actuals	Variance Over / (Under)
Opex Related to Capex	$435,000	$242,963	($192,037)
Repair & Inspections Related Costs	$600,000	$465,204	($134,796)
System Planning & Protection Coordination Study	$25,000	$0	($25,000)
VVO/CRV Program	$432,000	$138,139	($293,861)
Total I&M O&M Spending	**$1,492,000**	**$846,306**	**($645,694)**

For additional information of the Company's I&M program, deficiencies and repairs made, please see the Company's FY 2021 Electric Infrastructure, Safety, and Reliability Plan quarterly report for the fourth quarter period ending March 31, 2021 (Docket 4995) filed with the PUC on May 17, 2021. 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 2020, with SAIFI of 0.945 against a target of 1.05, and SAIDI of 69.1 minutes, against a target of 71.9 minutes. For additional information on reliability and major event days, please refer to the 2020 Service Quality Report filed under Docket 3628 on May 3, 2021. A copy is attached to this report as Attachment 2.

Attachment 1

Quarterly Report for the Fourth Quarter Period Ending March 31, 2021

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

May 17, 2021

VIA ELECTRONIC MAIL

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

RE: Docket 4995 – FY2021 Electric Infrastructure, Safety, and Reliability Plan
Quarterly Update – Fourth Quarter Ending March 31, 2021

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed an electronic version of the Company's fiscal year (FY) 2021 Electric Infrastructure, Safety, and Reliability (ISR) Plan quarterly update for the fourth quarter ending March 31, 2021.[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 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket 4995 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 Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by five (5) hard copies filed with the Clerk within 24 hours of the electronic filing.

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

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.

Joanne M. Scanlon

May 17, 2021
Date

Docket No. 4995 - National Grid's Electric ISR Plan FY 2021
Service List as of 1/29/2020

Name/Address	E-mail Distribution	Phone
Jennifer Hutchinson, Esq. **National Grid** 280 Melrose St. Providence, RI 02907	jennifer.hutchinson@nationalgrid.com; celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com;	401-784-7288
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Division of Public Utilities (Division) Christy Hetherington, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Chetherington@riag.ri.gov ; Dmacrae@riag.ri.gov; MFolcarelli@riag.ri.gov; John.bell@dpuc.ri.gov; Jonathan.Schrag@dpuc.ri.gov; Joseph.shilling@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
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File an original & ten copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.harrington@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Todd.bianco@puc.ri.gov; Alan.nault@puc.ri.gov; Margaret.hogan@puc.ri.gov;	401-780-2107

Electric Infrastructure, Safety, and Reliability Plan
FY 2021 Quarterly Update
For the Twelve months Ending March 31, 2021

EXECUTIVE SUMMARY

As shown in Attachment A during the fiscal year ending March 31, 2021, the Company[1] spent $100.7 million for capital projects against a Fiscal Year 2021 (FY 2021) budget of $103.8 million. Spending was under-budget by $3.0 million. FY 2021 Non-Discretionary spending was $2.7 million over the budget of $38.9 million. FY 2021 Discretionary spending, including the Southeast Substation project, was $5.7 million under the budget of $64.8 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 2021 Capital Spending by Key Driver Category

1. Non-Discretionary Spending

a. Customer Request/Public Requirement

During the fiscal year ending March 31, 2021, capital spending in the Customer Request/Public Requirement category was $22.1 million which was under budget by $4.5 million. The major drivers are

- Activity for the year associated with a joint-owned pole agreement exceeded the amount budgeted resulting in additional credits applied to the New Business-Residential category. Activity for the year totaled $4.6 million which was higher than budgeted by $3 million and included billings million for prior year joint-owned pole installations as the Company finalized processes with Verizon. At the end of the fiscal year, billings by the Company under the joint-owned pole agreement lagged one month, which is the expected ongoing lag. Remaining activity under the blanket project and on specific projects was $1.5 million over the $5.7 million budgeted.
- Spending in the New Business Commercial category was $1.2 million under budget for the year. This variance was driven by underspending in both the blanket project and specific projects during the year.
- Spending in the Public Requirements category was $4.1 million under budget for the year. This variance was driven by Rhode Island Department of Transportation billings of $5.3 million included in the Public Requirements spending category.
- The projects associated with Meter Purchases and Installations are under budget by $1.4 million for FY 2021. Spending was less than the amount budgeted due to the purchase of fewer meters and decreased field activity for non-essential work. Some meter change work and installations requiring access to customers' homes or businesses and customer facing interactions were not done due to COVID-19 work restrictions.
- A minimal amount of spending took place for engineering of feeder monitors. This resulted in an underspending of $2.0 million in the Strategic DER Enabling Devices category for FY 2021.
- Billings for work that will take place in FY 2022 caused the Third-Party Attachment category to be under budget by $0.8 million at fiscal year-end.
- Activity in the Distributed Generation category was $6.6 million over budget, primarily due to the transition to the new process for recording customer Contribution in Aid of Construction (CIAC). Substantial progress was made on the transition to a new process for recording CIACs for DG projects at the work

order level to match CIACs in capital spending when the work is performed instead of all at once when received. Implementation of this new process will continue into FY 2022. Once the process has been fully implemented, the Company expects that the net capital activity for any fiscal year will be minimal.

b. Damage/Failure

During the fiscal year ending March 31, 2021, capital spending in the Damage/Failure category was $19.5 million, which was $7.1 million over the budget of $12.4 million. This variance is primarily driven by spending on major storms totaling $7.8 million, which is $6.1 million over the budget of $1.7 million. There were 12 major storm events in FY 2021 as compared with three in FY 2020. In addition, spending on the remaining Damage/Failure is over budget by $1.0 million. The Company began adopting the new process of 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 during FY 2021. As part of developing an estimate of how this new process will impact the Damage/Failure and Asset Replacement budgets, $2 million was reduced from the Damage/Failure budget in FY21 from the FY20 level and the Asset Replacement and Inspection & Maintenance (I&M) budgets were each increased $1 million over FY 20 budgets. The transition to the new process progressed throughout the fiscal year and the Company performed a monthly review of spending to ensure appropriate categorization. Monthly review of Damage/Failure work will continue in FY 2022.

2. Discretionary Spending

a. Asset Condition (without Southeast Substation)

During the fiscal year ending March 31, 2021, capital spending in the Asset Condition category (excluding the Southeast Substation project) was $28.9 million, which was $2.2 million under the budget of $31.0 million. The major drivers of this variance are as follows:

- Capital spending on Dyer Street substation was $3.9 million under the budget of $7.2 million. This project was paused in FY 2020 due to higher cost estimates than expected. The Company performed a revised option analysis which resulted in an updated project at reduced costs and created spending shifts from the first half of FY 2021 to the last half of FY 2021 and into FY 2022.
- Capital spending on the Providence Area Study projects (Admiral Street projects) was $1.6 million under the budget of $4.2 million primarily due to project delays

and capital efficiencies that were secured related to the use of an existing transformer rather than purchasing a new transformer.

- Capital spending on URD projects consisted of work that lagged from FY 2020 and new projects planned for FY 2021. As costs were increasing greater than budgeted some projects planned for FY2021 were deferred to FY 2022 to control spending. Costs increased $0.9 million over budget for FY 2021 due to increases in overtime costs to shorten outages to accommodate remote working, increased site costs due to underground conditions, and increased costs as a new vendor was replaced.
- Underground Cable Replacement program spending is $0.6 million over the $3.8 million budget due primarily to work time constraints that caused work to be performed at night at higher rates.
- The Apponaug Substation retirement, included in the Central Rhode Island East Area Study, was completed and put in service during FY 2021. Capital spending was $1.2 million and was $0.9 million more than the amount budgeted in FY 2021 as at the time the FY21 budget was estimated more work was expected to be completed in FY20 and was $0.6 million under budget.
- Two additional projects were completed during FY 2021 that were begun in prior years. Capital spending on Kent County Breaker Replacement project was $0.5 million and capital spending on a Distribution Secondary Network Arc project was $0.8 million. Both projects were expected to be completed in previous years and lagged into FY 2021 after the FY 2021 budget was set. These projects have been moved to plant in service.
- The Asset Replacement Blanket and I&M budgets were each increased in FY21 over the FY20 levels by $1 million (or $2 million combined) to estimate for the change in the process for classification of failed assets, as discussed above. The Asset Replacement blanket was $0.3 million over the FY 2021 budget of $4.5 million and the I&M program was $0.9 million under the FY 20201 budget of $2.9 million. Refer to the Damage/Failure section this report for additional information on the changes to the classification of failed assets and the Company's continuing review of Damage/Failure work.

b. __Non-Infrastructure__

During the fiscal year ending March 31, 2021 capital spending in the Non-Infrastructure was $0.6 million under budget. This variance is attributed to the application of capital overheads, which will be applied to projects in the following year.

c. ***System Capacity and Performance***

During the fiscal year ending March 31, 2021 capital spending for the System Capacity and Performance category was $17.4 million, which was $5.8 million under the budget of $23.1 million. The major drivers of this variance are as follows:

- Capital spending on the Aquidneck Island projects was $4.3 million under the budget of $13.5 million. Reductions in spending relate to COVID-19 work requirements shifting some construction costs into FY 2022, as well as the removal of contingencies once it was determined that a required outage could be scheduled during FY 2021.
- Capital spending on New Lafayette substation project was $0.5 million over the FY 2021 budget of $0.4 million as a result of advancing civil work to enable efficiencies by coordinating with a Distributed Generation project taking place on the same site.
- Capital spending on the East Providence substation was $1.3 million under the budget of $1.6 million due to project delays.
- Capital spending for the EMS Expansion program was $0.7 million under the budget of $1.0 million. Underspending was partially a result of pausing work at sites to allow for alignment with area studies.
- The Company spent $1.9 million for its 3V0 program and Strategic DER Advancement projects against a budget of $2.2 million in FY 2021. This was primarily driven by the purchase of four mobile 3V0 units that came in under the original estimate by $0.6 million.
- During FY 2021, the Company spent $0.3 million on COVID-19 related work and included the spending as Discretionary. This work included small-scale solutions such as fuse replacements, feeder balancing, and upgrading equipment such as load break switches and step-down transformers, to larger sizes.

d. ***Southeast Substation Projects***

During the fiscal year ending March 31, 2021, capital spending on the Southeast Substation project was $13.0 million, which was $2.9 million over the FY 2021 budget of $10.1 million due to a combination of project delays from FY 2020 and increased costs. The substation portion of this project is substantially complete and went into service in March 2021. The remaining substation work planned for FY 2022 is site civil work. The distribution line portion of this project is expected to be completed in FY 2022. In total, the Company currently expects capital spending to be $22.2 million for this project as compared with the estimate when sanctioned of $21.1 million. The difference of $1.8 million is primarily due to field conditions, requiring environmental management of an additional volume of soil, and additional resources, such as crane and other equipment rentals, to manage construction site congestion. See Attachment G for additional details.

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 $38.0 million of the FY 2021 budget of $103.8 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 recent COVID-19 scenario analysis utilized Python scrips to run the initial CYME analysis.

3. Investment Placed-in-Service

During the fiscal year ending March 31, 2021, $116.6 million of plant additions were placed in service which is 106% of the FY 2021 target of $110.5 million. Details by spending rationale are included in Attachment B.

As shown on Attachment B, Non-Discretionary plant additions placed in service during the fiscal year totaled $36.6 million, which is 109% of the FY 2021 target of $33.6 million. Discretionary plant additions placed in service during the same period totaled $80.0 million, which is 104% of the FY 2021 target of $76.9 million.

4. Vegetation Management (VM)

During the fiscal year ending March 31, 2021, the Company completed 1,215 miles or 100% of its annual distribution mileage cycle pruning goal. VM O&M spending was $10.7 million against a budget of $10.6 million.

Attachment C provides the spending for FY 2021 and an update of the gypsy moth and other pest-related damage tracked.

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

5. Inspection and Maintenance (I&M)

During the fiscal year ending March 31, 2021, the Company completed 100% of its annual structure inspection goal of 48,631 with an associated Opex spend 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 2021 no Level I deficiencies were found and the Company completed repairs for 33 percent of the total deficiencies found. This information is summarized in the table below.

Summary of Deficiencies and Repair Activities RI Distribution

Year Inspection Performed	Priority Level/Repair Expected	Deficiencies Found (Total)	Repaired as of 3/31/21	Not Repaired as of 3/31/21
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	16,492	9,391
	III	8,780	4,634	4,146
FY 2014	I	11	11	0
	II	22,096	4,375	17,721
	III	8,414	3,026	5,388
FY 2015	I	5	5	0
	II	20,805	1	20,804
	III	4,351	0	4,351
FY 2016	I	2	2	0
	II	11,018	1,072	9,946
	III	6,441	191	6,250
FY 2017	I	2	2	0
	II	8,567	0	8,567
	III	7,272	0	7,272
FY 2018	I	11	11	0
	II	8,639	11	8,628
	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	1	185
	III	26	0	26
FY 2021	I	0	0	0
	II	53	0	53
	III	37	0	37
Total Since Program Inception	**I, II, III**	**175,702**	**59,269**	**116,433**

Manual Elevated Voltage Testing				
Manual Elevated Voltage Testing	**Total System Units Requiring Testing**	**FY 2021 Units Completed thru 3/31/21**	**Units with Voltage Found (>1.0v)**	**Percent of Units Tested with Voltage (>1.0v)**
Distribution Facilities	268,651	45,875	0	0%
Underground Facilities	12,438	0	0	0%
Street Lights	4,929	1,135	0	0%

During FY 2021, the Company's manual elevated voltage testing has not indicated any instances of elevated voltage.

FY 2021 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 Twelve months Ending March 31, 2021
($000)

	FY 2021		
	Budget	**Actuals**	**Over Spend / (Under Spend)**
Customer Request/Public Requirement	$26,540	$22,079	($4,461)
Damage Failure	$12,365	$19,491	$7,126
Subtotal Non-Discretionary	*$38,905*	*$41,569*	*$2,664*
Asset Condition	$31,040	$28,865	($2,175)
Non-Infrastructure	$580	($57)	($637)
System Capacity & Performance	$23,145	$17,387	($5,758)
Subtotal Discretionary (excl. SE Sub)	*$54,765*	*$46,195*	*($8,570)*
Southeast Substation Project	$10,080	$12,951	$2,871
Subtotal Discretionary	*$64,845*	*$59,147*	($5,698)
Total Capital Spending	**$103,750**	**$100,716**	**($3,034)**

Attachment B

US Electricity Distribution - Rhode Island
Plant Additions by Spending Rationale
For the Twelve months Ending March 31, 2021
($000)

	Target	Actuals	% of Target In Service
Customer Request/Public Requirement	$21,210	$16,921	80%
Damage Failure	$12,335	$19,684	160%
Subtotal Non-Discretionary	*$33,545*	*$36,605*	109%
Asset Condition (w/Southeast Substation)	$38,948	$46,730	120%
Non- Infrastructure	$566	$197	35%
System Capacity & Performance	$37,435	$33,114	88%
Subtotal Discretionary	*$76,949*	*$80,041*	104%
Total Plant Additions	**$110,494**	**$116,646**	106%

Attachment C

US Electricity Distribution - Rhode Island
Vegetation Management O&M Spending
For the Twelve months Ending March 31, 2021
($000)

	Budget	Actual	% Spend
Cycle Pruning (Base)	$6,100	$5,968	98%
Hazard Tree	$1,750	$1,653	94%
Sub-T (on & off road)	$550	$397	72%
Police/Flagman Details	$775	$768	99%
Core Crew (all other activities)	$1,425	$1,900	133%
Total VM O&M Spending	**$10,600**	**$10,686**	**101%**

Gypsy Moth Update

District	Circuit	Location	Removals
Coastal	49_56_54F1	Coventry	65
Coastal	49_56_63F6	Hopkins Hill	48
Capital	49_53_15F1	Hope	9
Coastal	49_56_68F1	Kenyon	51
Capital	49_53_127W40	Nasonville	104
Capital	49_53_23F3	Farnum Pike	41
Capital	49_53_23F5	Farnum Pike	30
Capital	49_53_23F6	Farnum Pike	50
Capital	49_53_34F2	Chopmist	33
Capital	49_53_38F1	Putnam Pike	211
Capital	49_53_26W5	Woonsocket	9
Capital	49 53 26W3	Woonsocket	34
Totals			**685**

FY 2021 Gypsy Moth Update	
FY 2021 Total Gypsy Moth Spend	$922,820
Gypsy Moth Removals	685
Cost/Tree	$1,347

Attachment D

US Electricity Distribution - Rhode Island
Inspection and Maintenance Program and Other O&M Spending
For the Twelve months Ending March 31, 2021
($000)

	Budget	Actual	% Spend
Opex Related to Capex	$435	$243	56%
Inspections & Repair Related Costs	$600	$465	78%
System Planning & Protection Coordination Study	$25	$0	0%
VVO/CRV Program	$432	$138	32%
Total I&M Program and Other O&M Spending	$1,492	$846	

Attachment E

US Electricity Distribution - Rhode Island
Project Variance Report
For the Twelve months Ending March 31, 2021
($000)

Project Description	FY 2021 Budget	FY 2021 Actual	Over / (Under)	Variance Cause
Aquidneck Island Projects	$13,485	$9,215	($4,270)	Work shifting to FY 2022 and expecting lower project costs.
East Providence Substation	$1,550	$240	($1,310)	Project delays.
New Lafayette Substation	$390	$933	$543	Advancing civil work to enable efficiencies by coordinating with a DG project taking place on the same site.
Dyer Street Indoor Sub	$7,160	$3,239	($3,921)	Project paused as options were assessed. Rescoped project at reduced total costs and restarted in late FY21 shifting costs into FY22.
Providence Study	$4,240	$2,650	($1,590)	Project delays.
Franklin Sq Breaker Replacement	$1,135	$605	($530)	Due to COVID related issues, 4 breakers were delivered during FY 2021, but will be installed during FY 2022.
SouthEast Substation (D-Line and D-Sub)	$10,080	$12,951	$2,871	FY 2021 overspending is consistent with the underspending in FY 2020 due to project delays. Additional costs associated with soil management (environmental) and equipment rentals (construction site congestion) exceeded the amount budgeted for the year.
	$38,040	**$29,833**	**($8,207)**	

Attachment F

US Electricity Distribution - Rhode Island
Damage/Failure Detail by Work Type
For the Twelve months Ending March 31, 2021
($000)

	Project Type					
	D-Line Blanket	D-Line Property Damage	D-Line Storm	D-Sub Blanket	D-Sub & D-Line Specific	Grand Total
AFUDC	$62	$0	$58	$7	$0	**$127**
Default Accounting	$1,740	$403	$296	($60)	($2)	**$2,377**
Engineering/Design/Supervision	$677	$249	$703	$7	$4	**$1,640**
Outdoor Lighting - Cable/Wire	$9	$0	$0	$0	$0	**$9**
Outdoor Lighting - Framing	$68	$11	$3	$0	$0	**$82**
Outdoor Lighting - Poles/Foundation	$9	$2	$0	$0	$0	**$11**
Overhead Bonding/Grounding	$20	$3	$2	$0	$0	**$25**
Overhead Services	$229	$38	$234	$0	$0	**$501**
Overhead Switches/Reclosers/Fuses	$673	$235	$167	$0	$0	**$1,076**
OH Transformers/Capacitors/Regulators/Meters	$455	$171	$282	$0	$0	**$908**
Overhead Wire & Conductor	$373	$123	$321	$0	$0	**$817**
Pole Framing	$199	$105	$168	$0	($0)	**$473**
Poles/Anchors/Guying	$1,307	$1,330	$5,220	$0	$0	**$7,856**
Substation Equipment Installations	$0	$0	$0	$298	$465	**$762**
Substations Civil/Structural	$0	$0	$0	$0	$1	**$1**
Switching and Restoration	($2)	$18	$45	$1	$0	**$61**
Traffic Control	$306	$219	$182	$0	$0	**$707**
Underground Cable	$965	$282	$16	$0	$0	**$1,263**
Underground Cable Splicing	$28	$6	$4	$0	$0	**$38**
Underground Civil Infrastructure	$226	$240	$29	$0	$0	**$496**
Underground Direct-Buried Cable	$708	$71	$35	$0	$0	**$815**
Underground Services	$32	$1	$8	$0	$0	**$42**
Underground Switches/Reclosers/Fuses	$85	$6	$11	$0	$0	**$102**
UG Transformers/Capacitors/Regulators/Meters	$209	$20	$42	$0	$0	**$272**
Total	**$8,380**	**$3,534**	**$7,827**	**$252**	**$467**	**$20,461**
Reclassification adjustment between D/F and A/R	($970)	$0	$0	$0	$0	**($970)**
Adjusted Total	**$7,410**	**$3,534**	**$7,827**	**$252**	**$467**	**$19,491**

Attachment G

US Electricity Distribution - Rhode Island
New Southeast Substation Budget and Project Management Report
For the Twelve months Ending March 31, 2021

New Southeast Substation

Date: April 30, 2021

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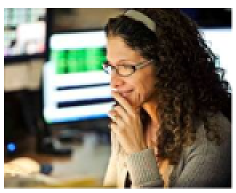

New Southeast Substation Project Agenda

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- Background & Drivers
- Scope
- Cost & Major Milestones
- Support Documentation
- Other

New Southeast Substation Project Background & Drivers

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- Pawtucket No. 1 substation supplies load in the City of Pawtucket, Rhode Island. It consists of an indoor substation located in a four story brick building constructed in 1907 and an outdoor substation on the yard. It supplies approximately 36,000 customers with a peak electrical demand of 114MW. There are a number of concerns in this area:
  - The equipment in the indoor substation is 40 to 94 years old, obsolete, and no longer supported by any vendor. Parts have to be custom made or salvaged from facilities removed from service.
  - The building has structural issues that cause concern for the continued safe and reliable operation of the substation.
  - There is un-served load for loss of either the 73 transformer or the 74 transformer that exceeds the distribution planning criteria.
  - The loading on a number of feeders is projected to exceed summer normal ratings along with the loading on bus section 73

New Southeast Substation Project Scope

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- Construct a new eight feeder 115/13.8kV metal clad station (Dunnell Park #1201) with two transformers and breaker and a half design on a site adjacent to the transmission line right of way on York Avenue in the City of Pawtucket.
- Supply the new station from the existing 115kV lines crossing the site, X-3 and T-7.
- Rearrange the 13.8kV distribution system so that the new station supplies most of the load east of the Seekonk River.
- Install a new control house at the Pawtucket No 1 station site to house the control equipment for the 115 kV station presently located in the four story brick building and upgrade the 115kV Line Protections (P-11,X-3,T-7).
- Upgrade in Valley station the 115kV Line Protections for P-11.
- Remove the indoor substation and all electrical equipment from the four story brick building and demolish the building.

New Southeast Substation Project Cost & Major Milestones

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Project Cost

- Total Project Cost of $38.182M (+/- 10%) DOA: $38.182M
- Transmission Project Cost of $12.742M (+/-10%)
- Distribution Project Cost of $25.440M (+/-10%)

New Southeast Substation Project Cost & Major Milestones

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- The variance between the initial potential project investment of $23.000M and this sanction of $38.182M was caused by:
  - Addition of new 115kV equipment on Pawtucket No. 1 and on the new substation (Dunnell Park #1201) as result of the review of protection requirements for the project. The updated scope includes the installation of 115kV CCVT's, Line Traps, Line Tuners and related relaying and civil & structural work on X-3 and T-7 transmission line terminals on both substations ($4.485M).
  - Additional civil and environmental scope of work on Pawtucket No. 1 based on the final location of the new control house inside the 100 year floodplain and the alignment with Tidewater Environmental Project requirements ($4.865M).
  - Underestimation on the scope and level of effort on the distribution line work for the new feeders and distribution circuits rearrangement on the City of Pawtucket ($4.517M).
  - Increase on equipment market value and other miscellaneous additional costs ($1.315M).

New Southeast Substation Project Major Milestones

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Project Major Milestones

Project Sanction	July 2019
Engineering Design Complete (EDC)	December 2019
Construction Start	January 2020
Dunnell Park Sub Ready for Load (RFL)	March 2021
Valley Sub Ready for Load (RLF)	June 2021
Pawtucket 1 Ready for Load (RFL)	June 2022
Construction Complete (CC)	August 2022
Demolish Pawtucket 1 Station Building	October 2022
Project Closeout	July 2023

New Southeast Substation Project Support Documentation

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New Southeast Station (Dunnell Park) – Location

Attachment H

US Electricity Distribution - Rhode Island
Meter Purchases
For the Twelve months Ending March 31, 2021

Quantity of Meters Purchased		
Type	**Description**	**Quantity**
METER	CENTRON - 2S ERT CL200	4,800
METER	CENTRON - 12S ERT CL200	960
METER	FOCUS - 2S 240VCL200	2,670
METER	FOCUS - 12S 120V CL200	45
METER	2S AMR 240V CL200	1,200
INSTRUMENT TRANSFORMER	CUR OUTDOOR 50/5 15KV	12
INSTRUMENT TRANSFORMER	CUR OUTDOOR 15/5 15KV	24
INSTRUMENT TRANSFORMER	CUR OUTDOOR 20/1 5KV	15
INSTRUMENT TRANSFORMER	CUR OUTDOOR 100/5 15KV	54
INSTRUMENT TRANSFORMER	CUR OUTDOOR 200/5 15KV	9
INSTRUMENT TRANSFORMER	CUR OUTDOOR 60/1 7.2KV	4
INSTRUMENT TRANSFORMER	CUR INDOOR 100/5 600V	120
INSTRUMENT TRANSFORMER	CT 100:5	60
INSTRUMENT TRANSFORMER	JVW5 NEES PT	8
INSTRUMENT TRANSFORMER	600:5 BASE BUSHINGS	30
INSTRUMENT TRANSFORMER	800:5 BASE BUSHINGS	60
INSTRUMENT TRANSFORMER	1500:5 CAP	24
INSTRUMENT TRANSFORMER	ASTRA DB 2.5 300:120	120
	TOTAL	**10,215**

Attachment 2

2020 Electric Service Quality Report

nationalgrid

Andrew S. Marcaccio
Senior Counsel

May 1, 2021

VIA ELECTRONIC MAIL

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

RE: Docket 3628 – 2020 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, 2020 through December 31, 2020 (the 2020 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 2020 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 ratepayers 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 practice during the COVID-19 emergency period, the Company is providing a PDF version of the 2020 Service Quality Report. The Company will provide the Commission Clerk with five (5) hard copies and, if needed, additional hard copies of the Report at a later date.
[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

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T: 401-784-4263 ■ andrew.marcaccio@nationalgrid.com ■ www.nationalgrid.com

For 2020, 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.

____
Joanne M. Scanlon

May 3, 2021
Date

National Grid – Electric Service Quality Plan – Compliance - Docket 3628
Service List Updated 5/3/2021

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

The Narragansett Electric Company
d/b/a National Grid

2020 Service Quality Report

May 1, 2021

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 six Major Event Days that occurred during 2020. The Major Event Days are February 7, April 13, August 4, September 30, October 7, and November 30.

2020 Total Frequency Standard		2020 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	0.945	$0
0.75-0.83	linear interpolation		
Less than 0.75	$229,000		

2020 Duration (SAIDI) Standard		2020 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	69.1	$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 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.

2020 Customer Contact Standard		2020 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	86.3%	$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.

2020 Calls Answered Standard		2020 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	81.98%	$0
90.5% - 100.0%	linear interpolation, to maximum of $46,000		

SECTION 2: CALCULATION OF PENALTY/OFFSET

National Grid
2020 Results of Service Quality Plan
Calculation of Penalty/Offset

Performance Standard	Potential Penalty (a)	Potential Offset (b)	2020 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	0.945	1.18	1.05	0.94	0.84	0.75	$0
Reliability - Duration	$ 916,000	$229,000	69.1	89.9	71.9	57.5	45.9	36.7	$0
Customer Service - Customer Contact Survey	$ 184,000	$ 46,000	86.3%	74.4%	78.8%	83.2%	87.6%	92.0%	$0
Customer Service - Telephone Calls Answered	$ 184,000	$ 46,000	82.0%	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 2020 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 2020 feeder ranking results on July 20, 2020, the second quarter results on December 18, 2020, the third quarter results on March 19, 2021 and fourth quarter results on March 26, 2021.

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 2020, with the final report for the 13 months ended December 2020 filed on January 21, 2021.

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

   Results: During 2020, the Company's annual meter reading performance (as an average of monthly percentage of meters read) was 98.19%, compared to 99.15% during 2019, and 99.06% during 2018. The following table details the percentage of meters read per month for 2020, 2019, and 2018.

Monthly Percentage of Meters Read

	2020	2019	2018
January	99.01%	99.21%	98.93%
February	99.07%	99.23%	99.01%
March	98.72%	99.26%	98.19%
April	97.85%	99.29%	99.11%
May	97.88%	99.32%	99.13%
June	97.67%	99.29%	99.19%
July	97.92%	99.24%	99.11%
August	97.05%	99.22%	99.16%
September	98.27%	99.12%	99.24%
October	98.32%	98.70%	99.21%
November	98.38%	99.03%	99.19%
December	98.17%	98.94%	99.20%
YTD Average	98.19%	99.15%	99.06%

4. **Reporting Requirement:** 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.

Results: 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 2020 the T_{MED} value was 6.03 minutes of SAIDI (using IEEE Std. 1366-2012 methodology). There were six storms that exceeded this threshold in 2020. These six storms occurred on February 7, April 13, August 4, September 30, October 7 and November 30. 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.

February 7, 2020 Storm

1. Start Date and Time of event:

   The storm began in the early afternoon on Friday, Feb 7, 2020 with scattered interruptions starting at approximately 7:00 a.m. and peaked around 5:07 p.m. on Feb 7, 2020. The peak reached 42,695 customers interrupted.

2. Number/Location of crews on duty (both internal and external crews):
   The Company secured 341 internal and external field crews1 to restore power to customers in Rhode Island, consisting of approximately 202 external crews and 139 internal crews. The internal and external field crew numbers 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.

Location	Crew Type	# Crews
Rhode Island	Internal Overhead Line	141 crews total
	External Overhead Line	165 crews total
	Internal Wire Down	131 crews total
	Internal Transmission	3 crews total
	Internal Underground	12 crews total
	Internal Substation	50 crews total
	Contractor Forestry	160 crews total

4. The first instance of mutual aid coordination:
   The first call for mutual aid coordination for this event started at February 7, 2020; 5:30 p.m.

5. The first contact with material suppliers:
   The first contact with material suppliers started on February 7, 2020.

6. Inventory levels: Pre-event/Daily/Post-event:

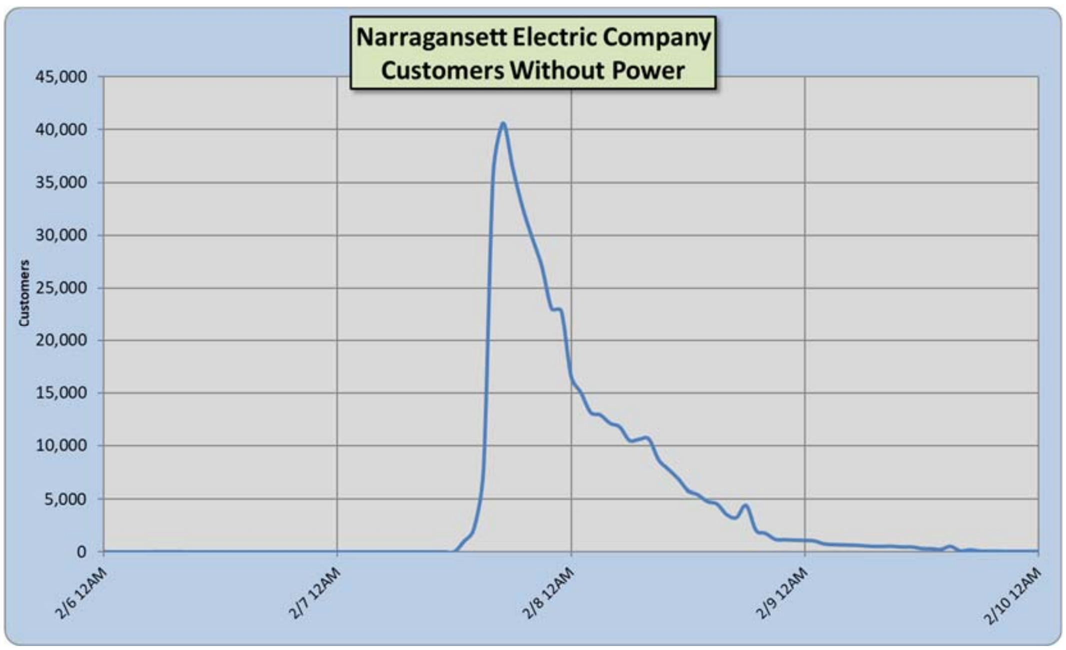
Event Date	RI Inventory Locations	Allocated NEDC Inventory	Total Inventory
2/7/2020	$748,855	$7,654,538	$8,403,393

7. Date/Time of request for External Crews:

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

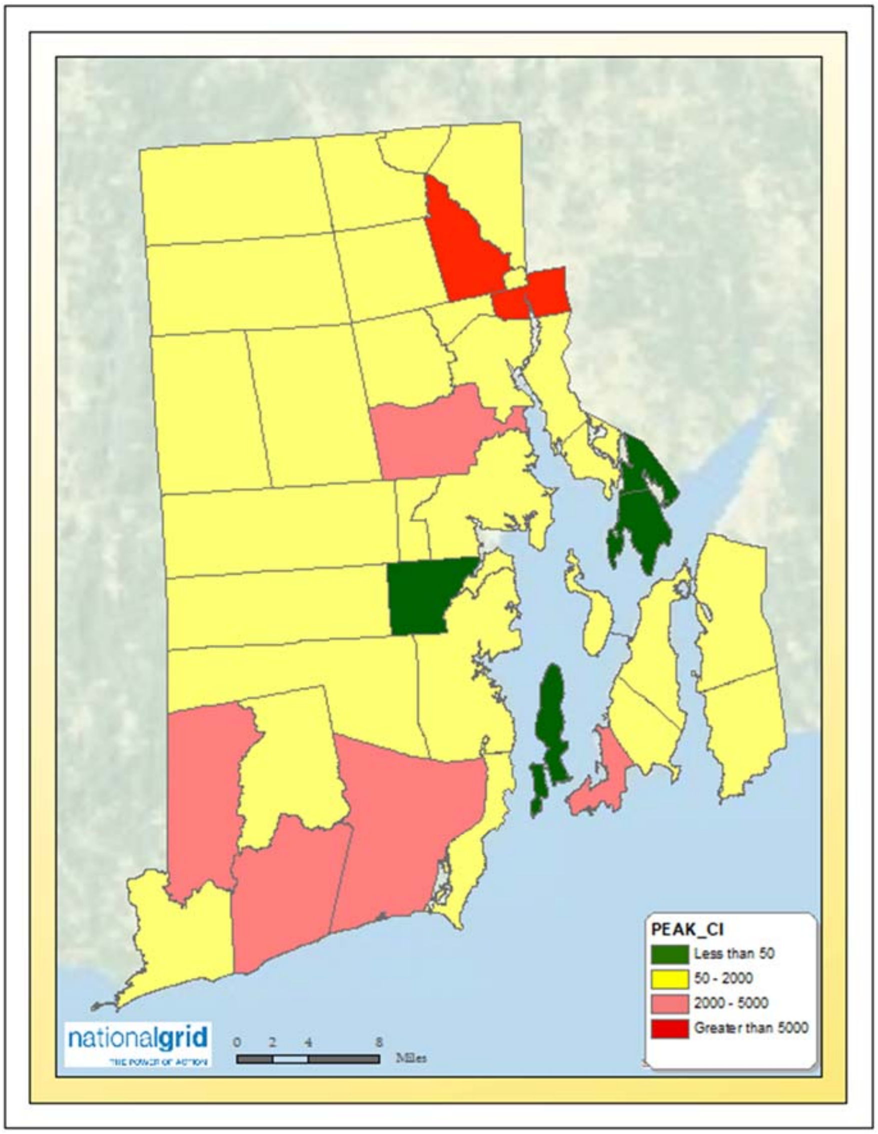
8. Date/Time of external Crews assignment:
   Mutual Assistance was assigned to duty staring 5:30pm on February 7, 2020.

9. # of customers out graph (graphs following):

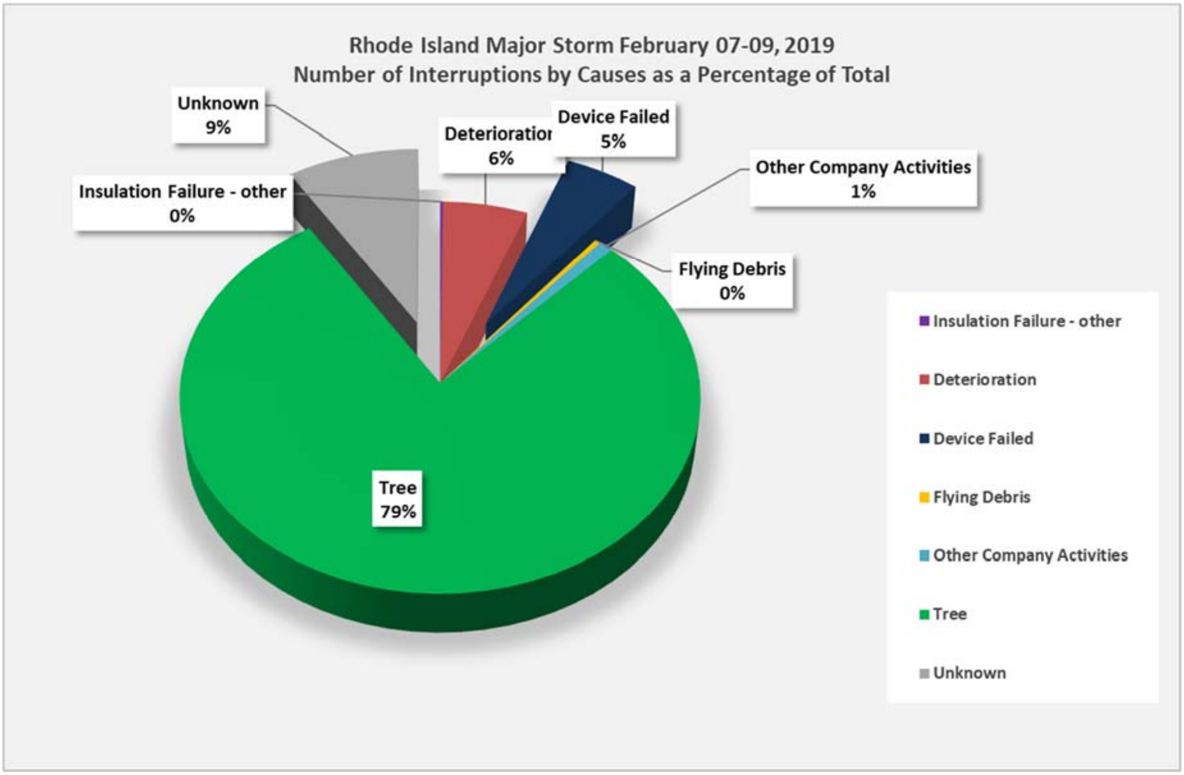


10. Impacted area:

Customer Interrupted by Town at Company Peak
RI 02/07/2020 to 02/08/2020



11. Cause:



12. Weather impact on restoration:

The February 7-8, 2020 Storm was a significant weather event that resulted in moderate damage to the Company's electrical system. The Storm brought some rain and widespread hazardous winds to the Company's service territory. Much of Rhode Island experienced wind gusts in the 40 to 55 mph range, with some areas seeing 55 to 60 mph gusts. The City of Providence experienced peak gusts of 60 mph. The Towns of Little Compton and Lincoln were affected most heavily with approximately 100 and 76 percent of their customers impacted, respectively, 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, propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of a mis-operation.

14. Summary of Customers Impacted:

February 7, 2020

During this storm, on February 7, 2020 Rhode Island experienced a total of 251 interruptions that affected 55,732 customers and 26,545,799 customer minutes of interruption. On average these interruptions resulted in 0.112 SAIFI, 53.31 minutes of SAIDI. Since a SAIDI value of 53.31 minutes exceeded the threshold value of 6.03 minutes, February 07, 2019 qualified as a Major Event Day under the IEEE methodology.

February 8, 2020

During this storm, on February 8, 2020 Rhode Island experienced a total of 39 interruptions that affected 951 customers and 210,966 customer minutes of interruption. On average these interruptions resulted in 0.002 SAIFI, 0.42 minutes of SAIDI. Since a SAIDI value of 0.42 minutes is less than the threshold value of 6.03 minutes, February 08 is not qualified as a Major Event Day under the IEEE methodology.

April 13, 2020 Storm

1. Start Date and Time of event:

   The storm began in the early morning on Monday, April 13, 2020 with scattered interruptions starting at approximately 6:00 a.m. and peaked around 6:21 p.m. on April 13, 2020. The peak reached 21,104 customers interrupted.

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

   The Company secured 323 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 123 external crews and 206 internal crews. The internal and external field crew numbers included transmission and distribution overhead line, forestry, substation, wires-down, 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.

Location	Crew Type	# Crews
Rhode Island	Internal Overhead Line	134 crews total
	External Overhead Line	106 crews total
	Internal Wire Down	212 crews total
	Internal Transmission	2 crews total
	Internal Underground	26 crews total
	Internal Substation	60 crews total
	Contractor Forestry	131 crews total

4. The first instance of mutual aid coordination:
   The first call for mutual aid coordination for this event started at April 14, 2020, 8:00 a.m.

5. The first contact with material suppliers:
   The first contact with material suppliers started on April 13, 2020.

6. Inventory levels: Pre-event/Daily/Post-event:

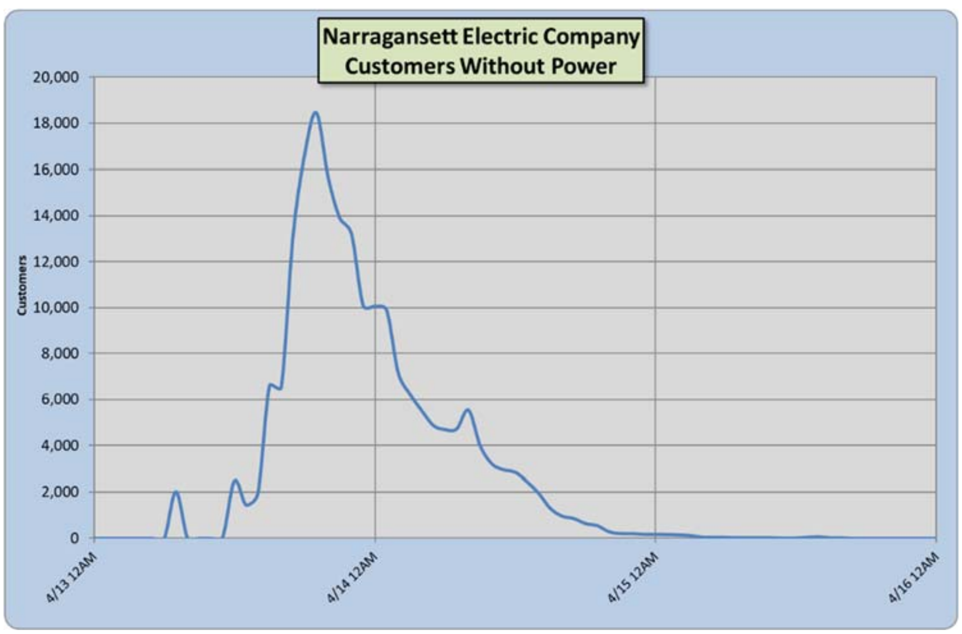
Event Date	RI Inventory Locations	Allocated NEDC Inventory	Total Inventory
4/13/2020	$720,506	$7,193,930	$7,914,435

7. Date/Time of request for External Crews:

   Given the potential magnitude of the Storm and forecast of significant rain and 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. The first North Atlantic Mutual Assistance Group call was on April 11, 2020, 10:30pm.

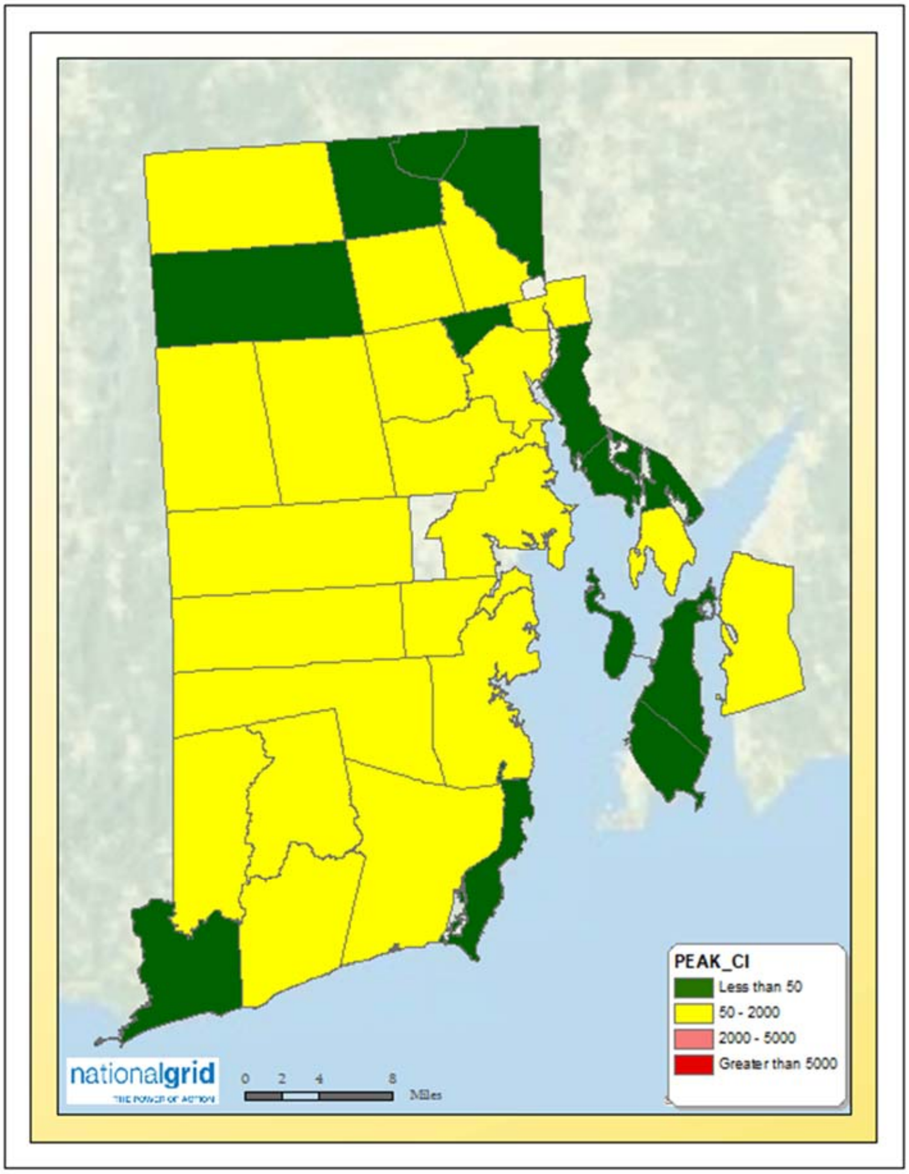
8. Date/Time of external Crews assignment:
   Mutual Assistance was assigned to duty staring 5:30pm on February 7, 2020.

9. # of customers out graph (graphs following):

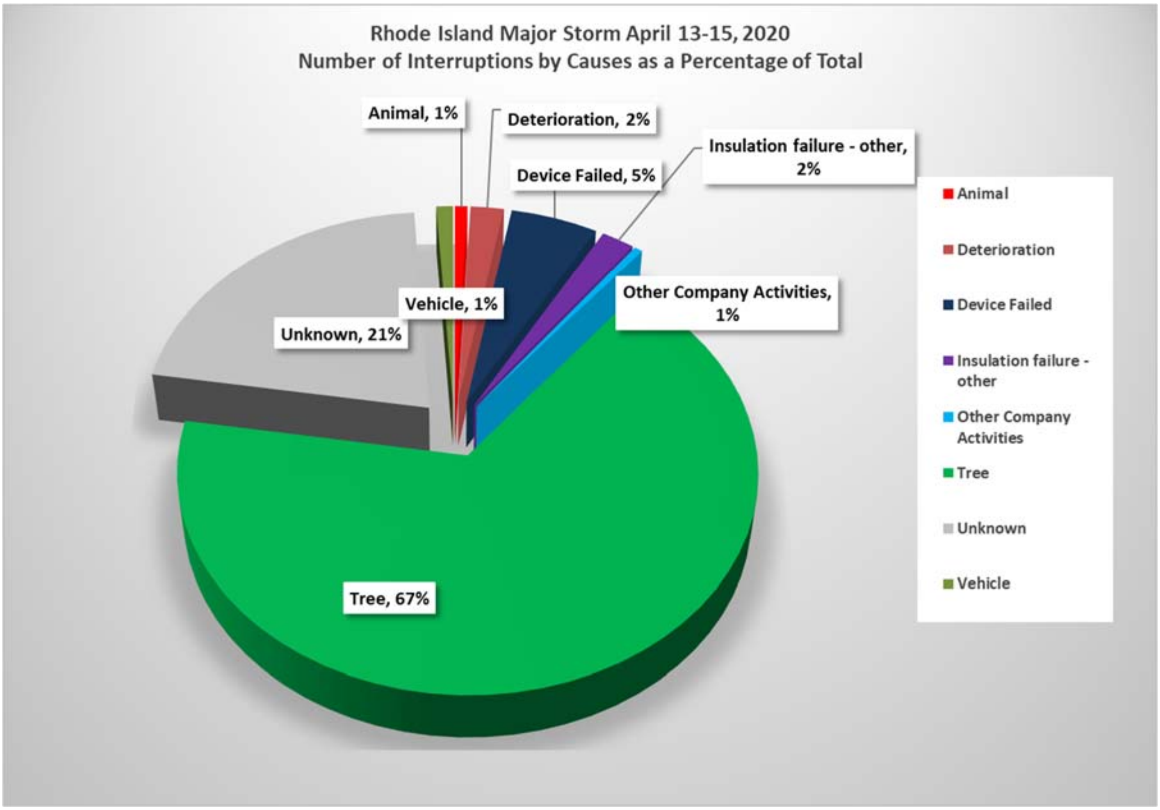


10. Impacted area:

Customer Interrupted by Town at Company Peak
RI 04/13/2020 to 04/15/2020



11. Cause:



12. Weather impact on restoration:

The April 13, 2020 Storm was a significant weather event that resulted in moderate damage to the Company's electrical system. The Storm brought widespread rain and hazardous winds to the Company's service territory. The Towns of Burrillville and Glocester were affected most heavily with approximately 94 and 80 percent of their customers impacted, respectively, 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, propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of a mis-operation.

14. Summary of Customers Impacted:

April 13, 2020

During this storm, on April 13, 2020 Rhode Island experienced a total of 253 interruptions that affected 31,432 customers and 12,319,294 customer minutes of interruption. On average these interruptions resulted in 0.0631 SAIFI, 24.73 minutes of SAIDI. Since a SAIDI value of 24.73 minutes exceeded the threshold value of 6.03 minutes, April 13, 2020 qualified as a Major Event Day under the IEEE methodology.

April 14, 2020

During this storm, on April 14, 2020 Rhode Island experienced a total of 53 interruptions that affected 2,303 customers and 230,332 customer minutes of interruption. On average these interruptions resulted in 0.0046 SAIFI, 0.46 minutes of SAIDI. Since a SAIDI value of 0.46 minutes is less than the threshold value of 6.03 minutes, April 14, 2020 is not qualified as a Major Event Day under the IEEE methodology. The restoration continued April 15, 2020. The SAIDI on April 15, 2020 is 0.05 min and will not be qualified as Major storm day.

August 4, 2020 Storm Isaias

1. Start Date and Time of event:

   The storm began in the afternoon on Tuesday, August 4, 2020 with scattered interruptions starting at approximately 3:00 p.m. and peaked around 6:49 p.m. on August 4, 2020. The peak reached 115,339 customers interrupted.

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

   The Company secured 372 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 186 external crews and 186 internal crews. The internal and external field crew numbers included transmission and distribution overhead line, forestry, substation, wires-down, 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.

Location	Crew Type	# Crews
Rhode Island	Internal Overhead Line	196 crews total
	External Overhead Line	577 crews total
	Internal Wire Down	204 crews total
	Internal Transmission	4 crews total
	Internal Underground	40 crews total
	Internal Substation	144 crews total
	Contractor Forestry	332 crews total

4. The first instance of mutual aid coordination:
   The first call for mutual aid coordination for this event started at August 4, 2020, 8:00 p.m.

5. The first contact with material suppliers:
   The first contact with material suppliers started on August 4, 2020.

6. Inventory levels: Pre-event/Daily/Post-event:

Event Date	RI Inventory Locations	Allocated NEDC Inventory	Total Inventory
8/4/2020	$910,217	$7,153,908	$8,064,125

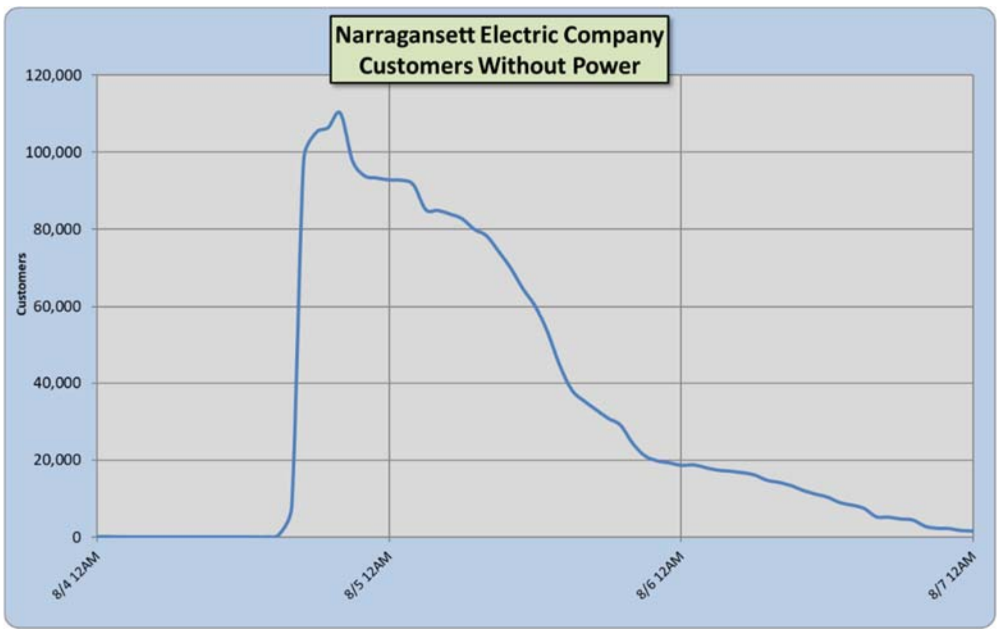
7. Date/Time of request for External Crews:

The State Incident Commander for National Grid's Rhode Island and Massachusetts electric distribution operating companies 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 on July 31, 2020, 3:00 pm.

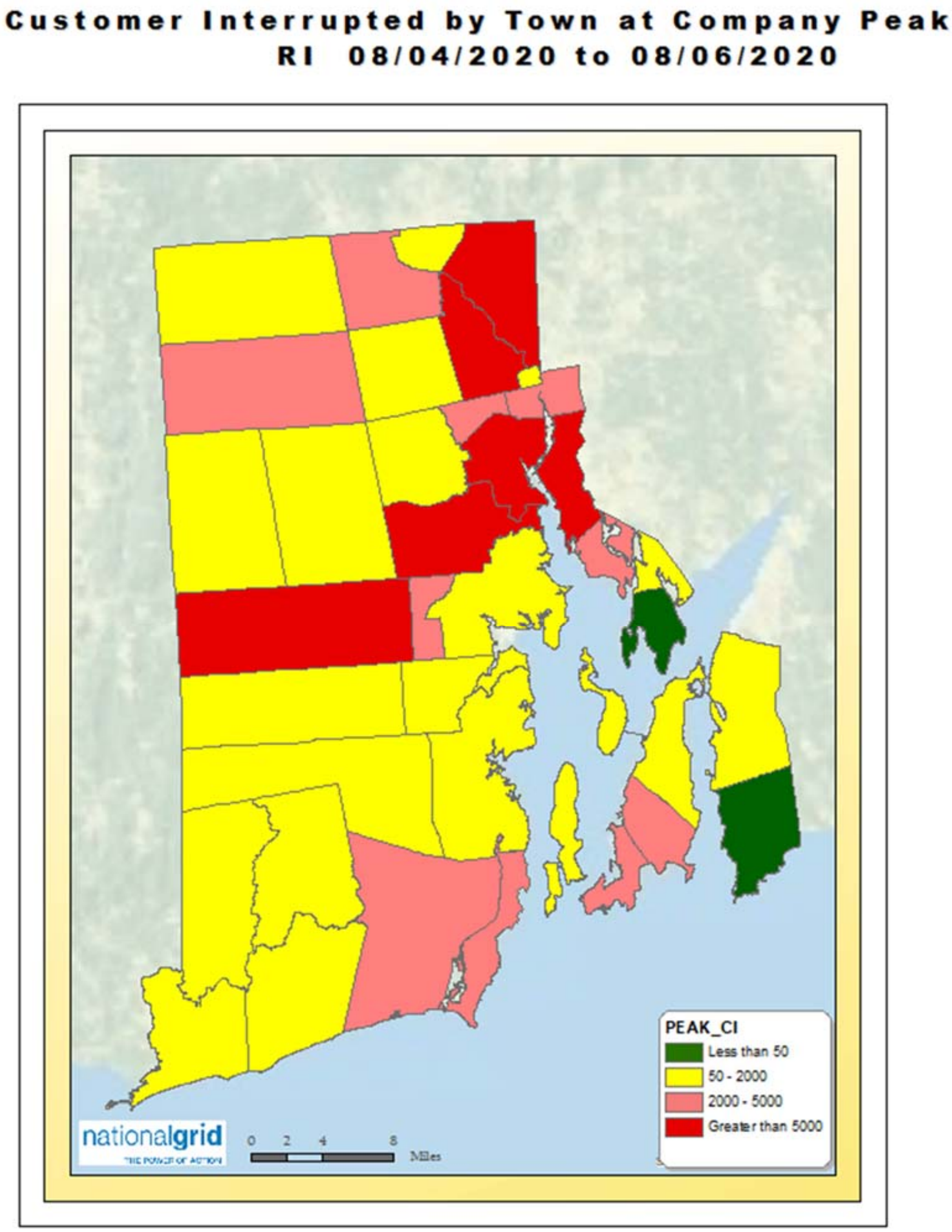
8. Date/Time of external Crews assignment:

Mutual Assistance was assigned to duty staring 8:00pm on August 4, 2020.

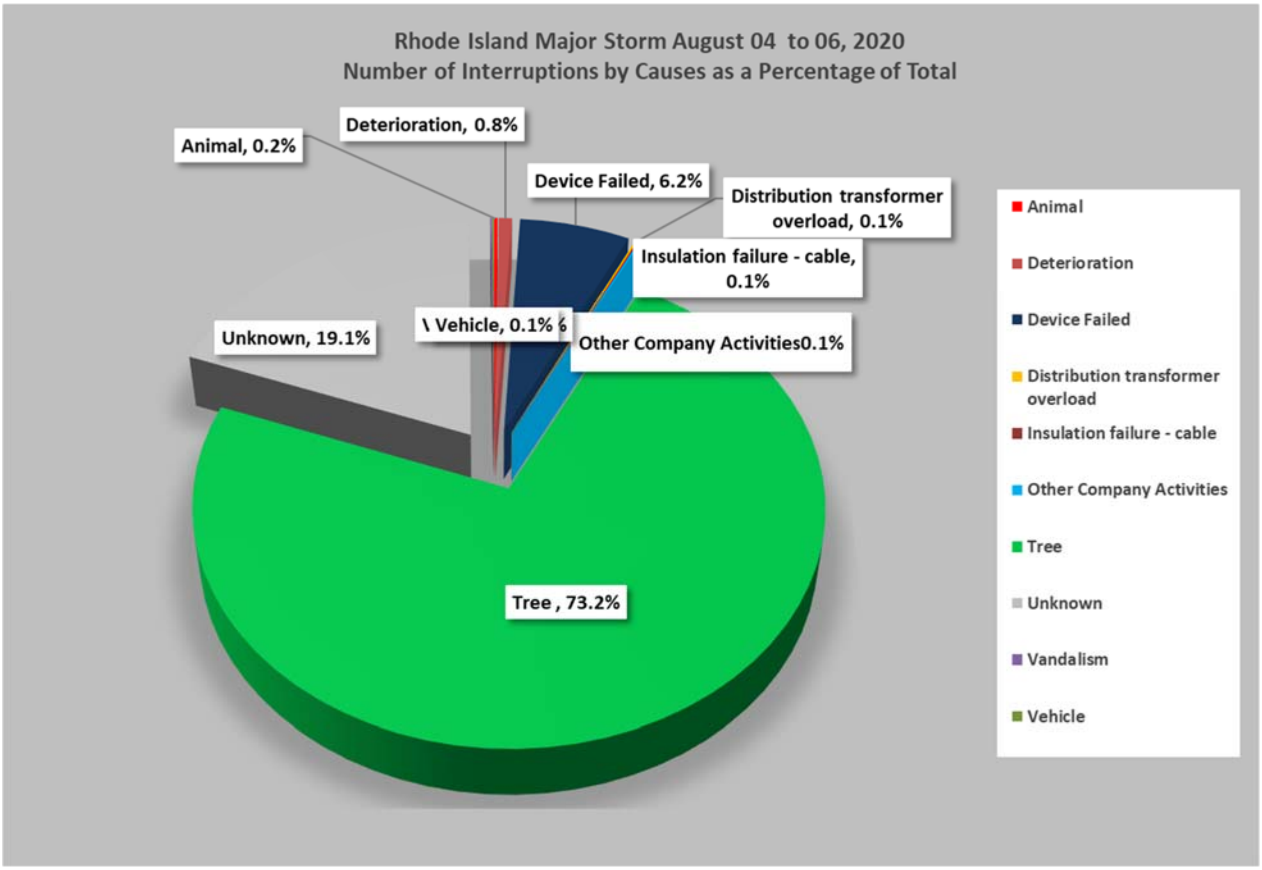
9. # of customers out graph (graphs following):



10. Impacted area:



11. Cause:



12. Weather impact on restoration:

Tropical Storm Isaias was a significant weather event that resulted in significant damage to the Company's electrical system. The Storm brought widespread rain and hazardous winds to the Company's service territory. The Towns of Exeter and Coventry were affected most heavily with approximately 96 and 79 percent of their customers impacted, respectively, 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, propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of a mis-operation

14. Summary of Customers Impacted:

August 4, 2020

During this storm, on August 4, 2020 Rhode Island experienced a total of 572 interruptions that affected 130,386 customers and 141,204,376 customer minutes of interruption. On average these interruptions resulted in 0.262 SAIFI, 283.464 minutes of SAIDI. Since a SAIDI value of 283.464 minutes exceeded the threshold value of 6.03 minutes, August 4, 2020 qualified as a Major Event Day under the IEEE methodology.

August 5, 2020

During this storm, on August 5, 2020 Rhode Island experienced a total of 73 interruptions that affected 2,602 customers and 693,650 customer minutes of interruption. On average these interruptions resulted in 0.005 SAIFI, 1.39 minutes of SAIDI. Since a SAIDI value of 1.39 minutes is less than the threshold value of 6.03 minutes, August 5, 2020 is not qualified as a Major Event Day under the IEEE methodology. The restoration continued August 6, 2020. The SAIDI on August 6, 2020 is 0.499 min and will not be qualified as Major storm day.

September 30, 2020 Storm

1. Start Date and Time of event:

   The storm began in the early morning on Wednesday, September 30, 2020 with scattered interruptions starting at approximately 4:00 a.m. and peaked around 8:38 p.m. on September 30, 2020. The peak reached 24,458 customers interrupted.

2. Number/Location of crews on duty (both internal and external crews):
   The Company secured a total of 286 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 126 external crews and 160 internal crews. The internal and external field crew numbers 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.

Location	Crew Type	# Crews
Rhode Island	Internal Overhead Line	136 crews total
	External Overhead Line	97 crews total
	Internal Wire Down	50 crews total
	Internal Transmission	2 crews total
	Internal Underground	25 crews total
	Internal Substation	72 crews total
	Contractor Forestry	68 crews total

4. The first instance of mutual aid coordination:
   No mutual aid was called for this storm.

5. The first contact with material suppliers:
   The first contact with material suppliers started on September 30, 2020.

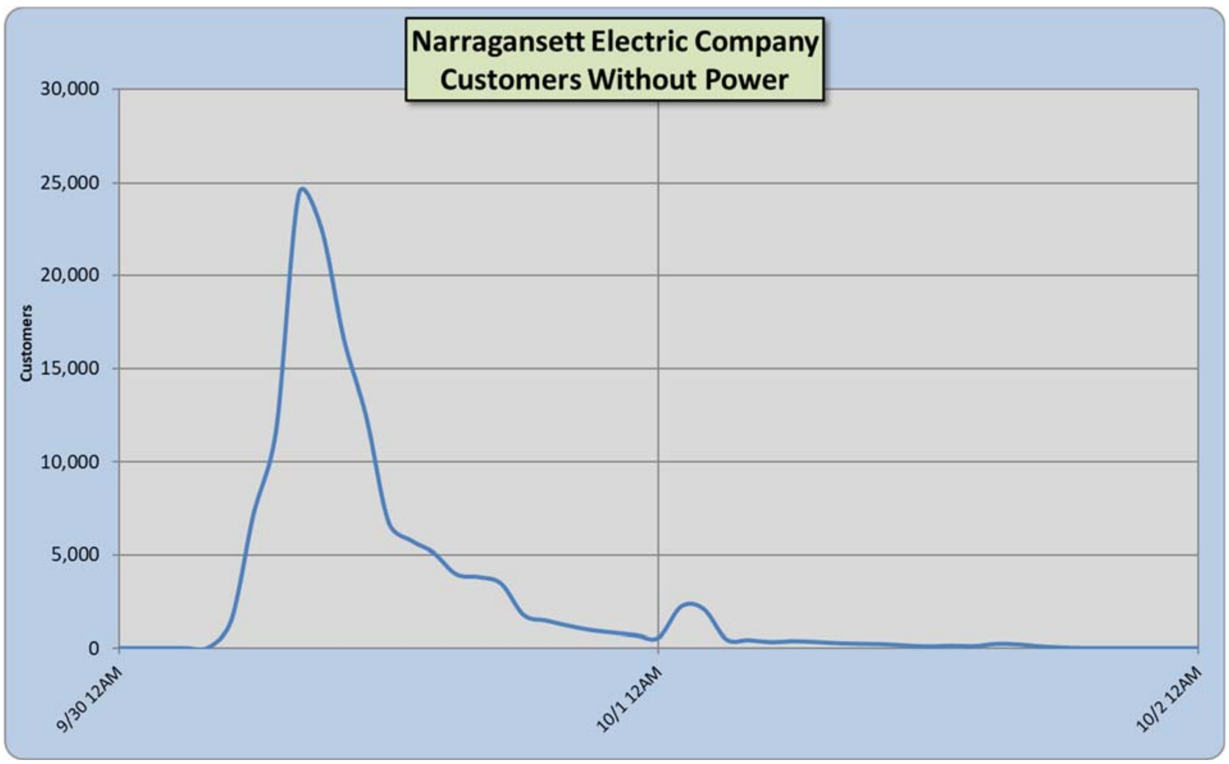
6. Inventory levels: Pre-event/Daily/Post-event:

Event Date	RI Inventory Locations	Allocated NEDC Inventory	Total Inventory
9/30/2020	$1,006,312	$6,946,754	$7,953,067

7. Date/Time of request for External Crews:
   The State Incident Commander for National Grid's Rhode Island was able to obtain sufficient external contractor crews, as well as some Forestry crews from the Company's sister utility in New York, to supplement restoration efforts in New England. No additional assistance was required from companies in the North Atlantic Mutual Assistance Group ("NAMAG") to support restoration for this event.

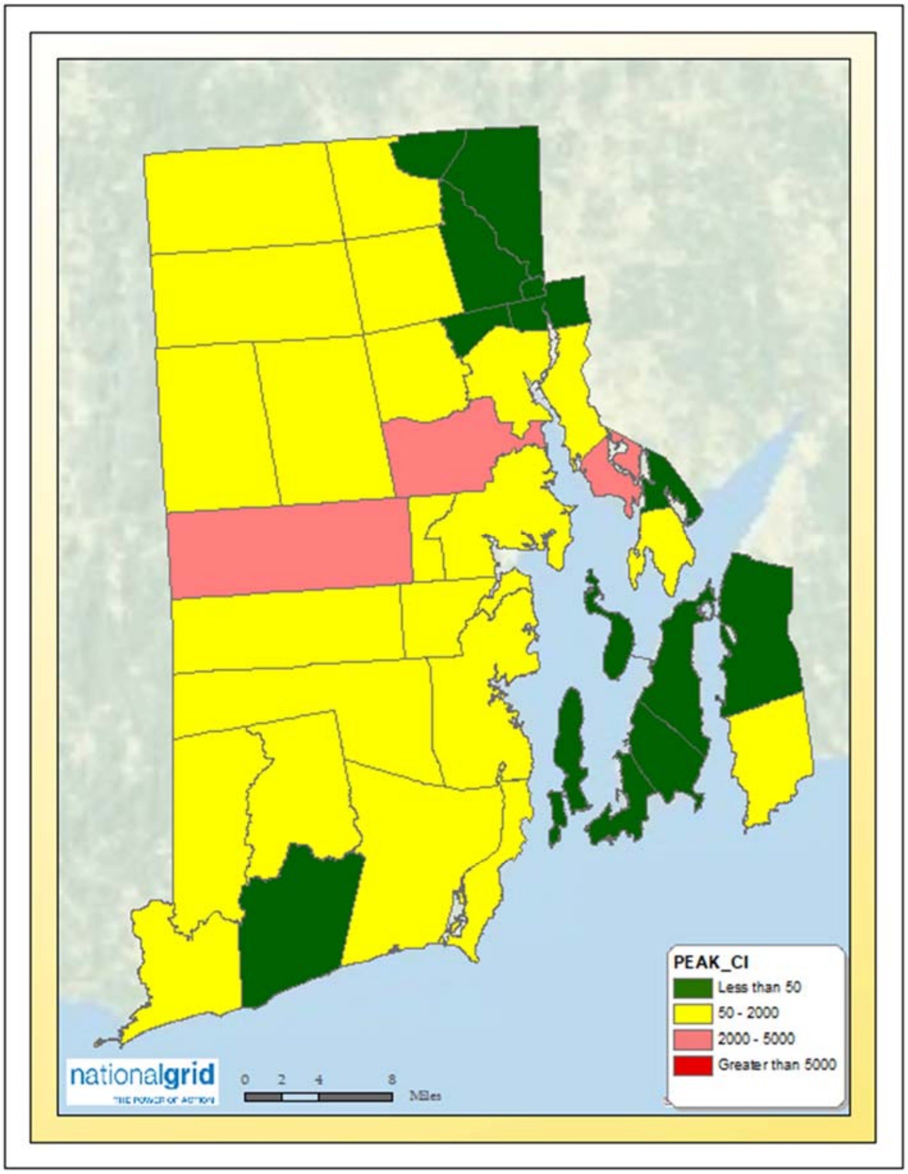
8. Date/Time of external Crews assignment:
   Mutual Assistance was not called for this storm.

9. # of customers out graph (graphs following):

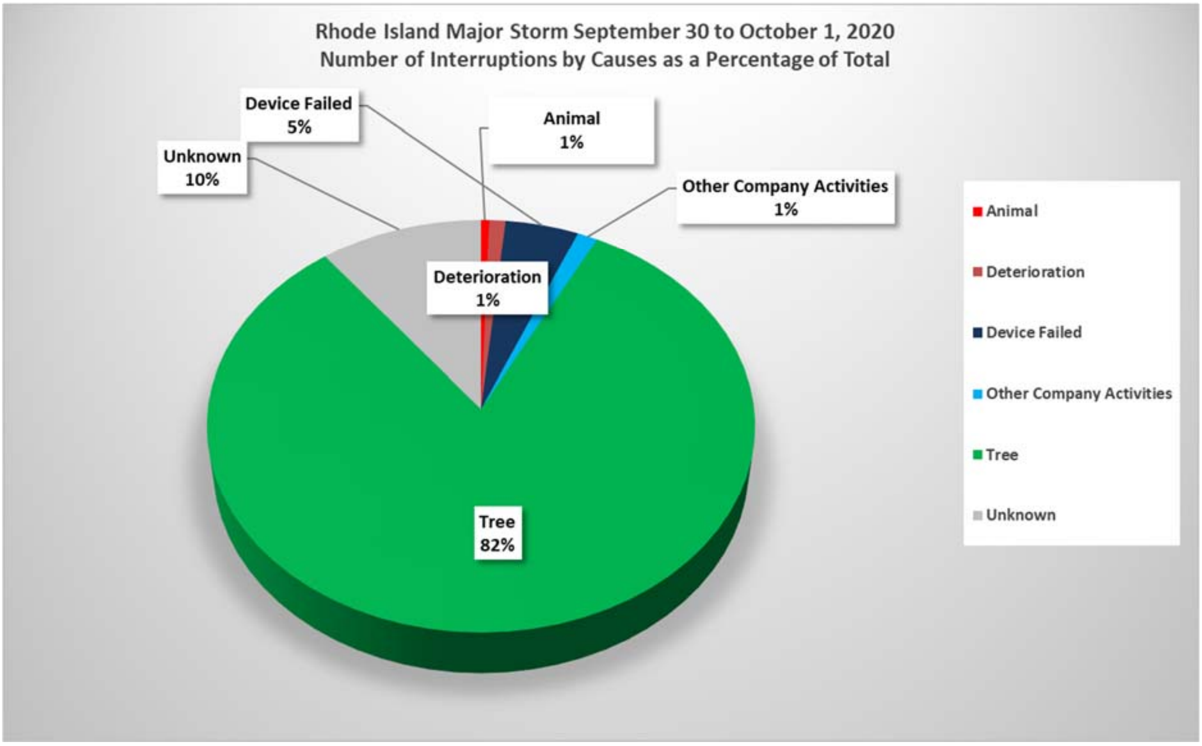


10. Impacted area:

Customer Interrupted by Town at Company Peak
RI 09/30/2020 to 10/01/2020



11. Cause:



12. Weather impact on restoration:

The September 29-30, 2020 Storm was a significant weather event that resulted in moderate damage to the Company's electrical system. The Storm brought some rain, thunderstorms, and widespread hazardous winds to the Company's service territory. Parts of Rhode Island experienced wind gusts in the 40 to 50 mph range, with some areas seeing even higher gusts. The City of Providence experienced a peak gust of 56 mph. The Towns of Jamestown, Glocester, and Coventry were affected most heavily with approximately 47 percent of their 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, propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of a mis-operation.

14. Summary of Customers Impacted:

September 30, 2020

During this storm, on September 30, 2020 Rhode Island experienced a total of 348 interruptions that affected 34,721 customers and 10,092,529 customer minutes of interruption. On average these interruptions resulted in 0.070 SAIFI, 20.25 minutes of SAIDI. Since a SAIDI value of 20.25 minutes exceeded the threshold value of 6.03 minutes, September 30, 2020 qualified as a Major Event Day under the IEEE methodology.

October 1, 2020

During this storm, on October 1, 2020 Rhode Island experienced a total of 64 interruptions that affected 2,421 customers and 247,822 customer minutes of interruption. On average these interruptions resulted in 0.005 SAIFI, 0.497 minutes of SAIDI. Since a SAIDI value of 0.497 minutes is less than the threshold value of 6.03 minutes, October 1, 2020 is not qualified as a Major Event Day under the IEEE methodology.

October 7, 2020 Storm

1. Start Date and Time of event:

   The storm began in the morning on Wednesday, October 7, 2020 with scattered interruptions starting at approximately 10:00 a.m. and peaked around 7:41 p.m. on October 7th, 2020. The peak reached 42,814 customers interrupted.

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

   The Company secured a total of 247 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 115 external crews and 132 internal crews. The internal and external field crew numbers 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.

Location	**Crew Type**	**# Crews**
Rhode Island	Internal Overhead Line	183 crews total
	External Overhead Line	194 crews total
	Internal Wire Down	72 crews total
	Internal Transmission	3 crews total
	Internal Underground	31.5 crews total
	Internal Substation	108 crews total
	Contractor Forestry	171 crews total

4. The first instance of mutual aid coordination:
   Mutual aid was not called for this storm.

5. The first contact with material suppliers:
   The first contact with material suppliers started on October 7, 2020.

6. Inventory levels: Pre-event/Daily/Post-event:

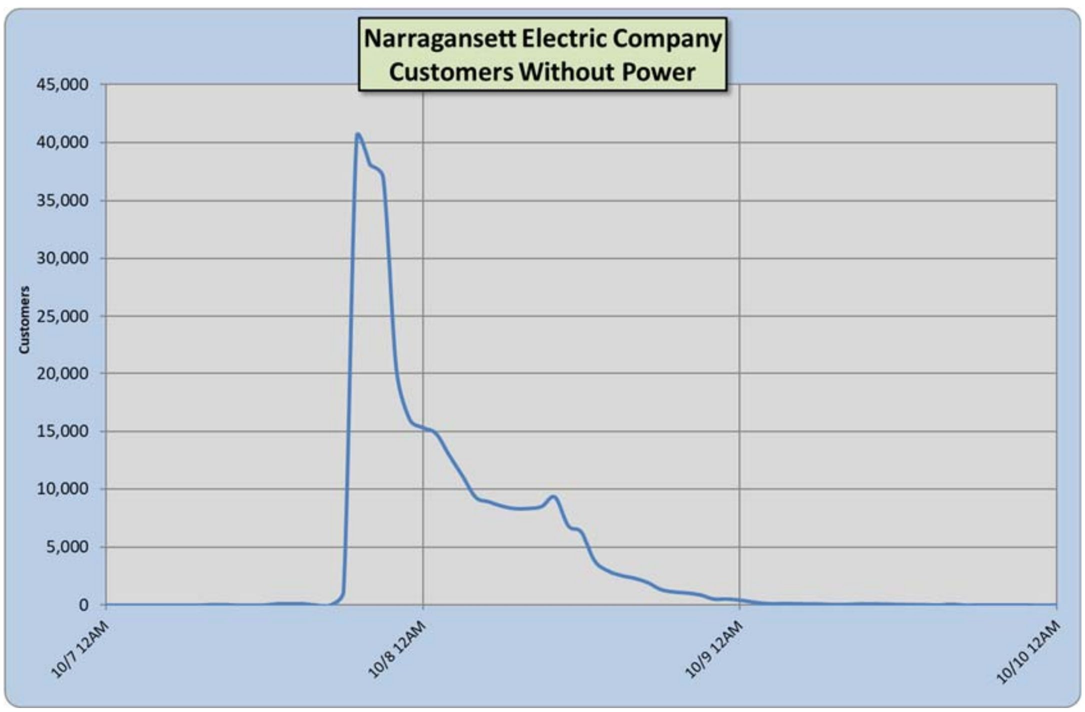
Event Date	RI Inventory Locations	Allocated NEDC Inventory	Total Inventory
10/7/2020	$908,625	$6,904,389	$7,813,015

7. Date/Time of request for External Crews:

   The State Incident Commander for National Grid's Rhode Island was able to obtain sufficient external contractor crews, as well as some Forestry crews from the Company's sister utility in New York, to supplement restoration efforts in New England. No additional assistance was required from companies in the North Atlantic Mutual Assistance Group ("NAMAG") to support restoration for this event.

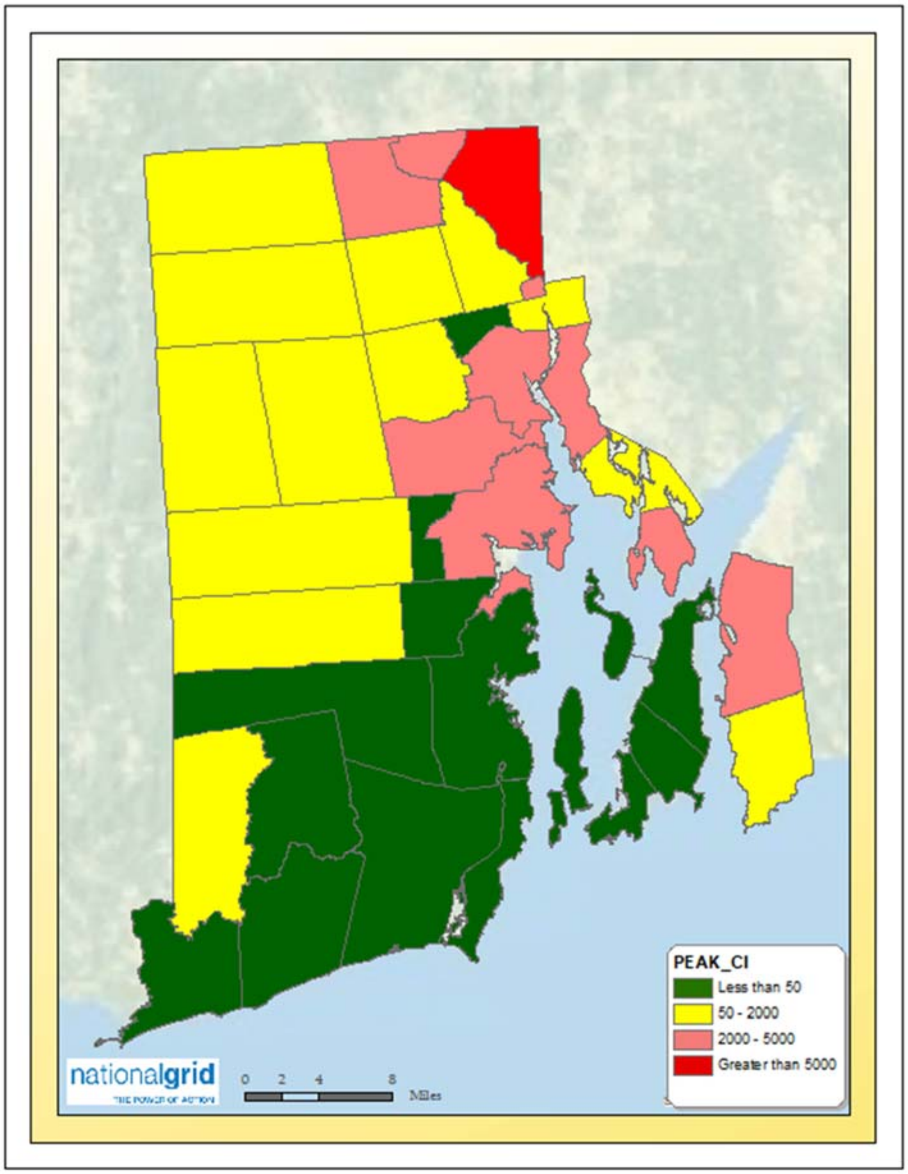
8. Date/Time of external Crews assignment:
   Mutual Assistance was not called for this storm.

9. # of customers out graph (graphs following):

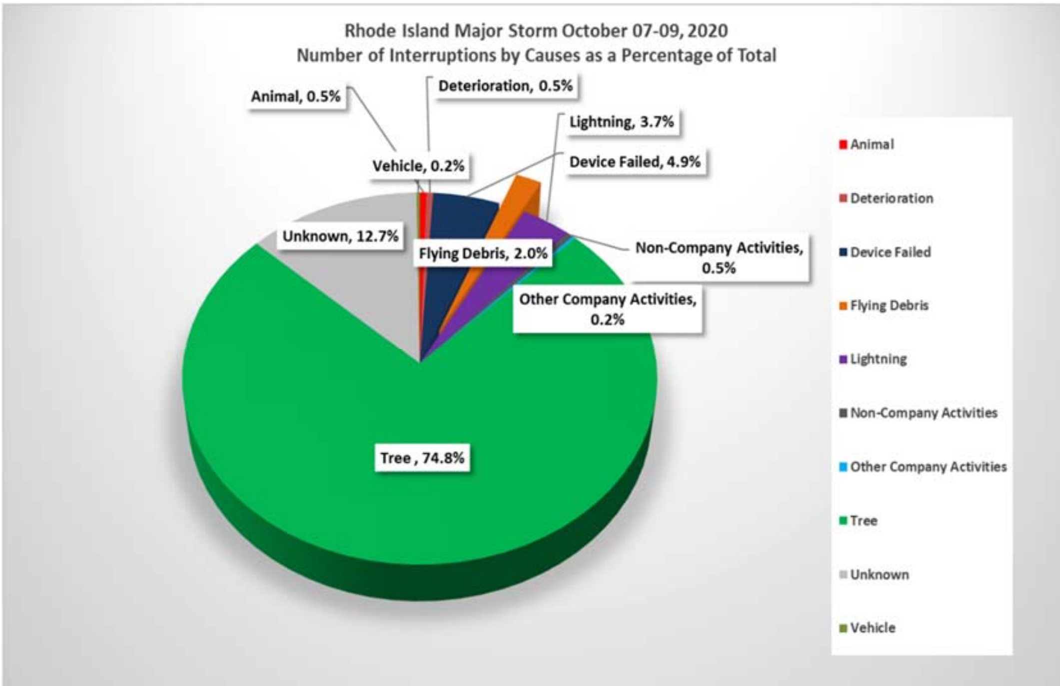


10. Impacted area:

Customer Interrupted by Town at Company Peak
RI 10/07/2020 to 10/09/2020



11. Cause:



12. Weather impact on restoration:

The October 7-9, 2020 Storm was a significant weather event that resulted in moderate damage to the Company's electrical system. The Storm brought some rain, thunderstorms, and widespread hazardous winds to the Company's service territory. Parts of Rhode Island experienced wind gusts in the 45 to 55 mph range, with some areas seeing even higher gusts. The Towns of North Smithfield and Little Compton and the City of Central Falls were affected most heavily with between approximately 36-45 percent of their 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, propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of a mis-operation.

14. Summary of Customers Impacted:

October 7, 2020

During this storm, on October 7, 2020 Rhode Island experienced a total of 243 interruptions that affected 43,866 customers and 17,835,777 customer minutes of interruption. On average these interruptions resulted in 0.088 SAIFI, 35.78 minutes of SAIDI. Since a SAIDI value of 35.78 minutes exceeded the threshold value of 6.03 minutes, October 7, 2020 qualified as a Major Event Day under the IEEE methodology.

October 8, 2020

During this storm, on October 8, 2020 Rhode Island experienced a total of 88 interruptions that affected 3,124 customers and 230,332 customer minutes of interruption. On average these interruptions resulted in 0.0063 SAIFI, 1.35 minutes of SAIDI. Since a SAIDI value of 0.46 minutes is less than the threshold value of 6.03 minutes, October 8, 2020 is not qualified as a Major Event Day under the IEEE methodology. The restoration continued October 9, 2020. The SAIDI on October 9, 2020 is 0.07 min and will not be qualified as Major storm day.

November 30, 2020 Storm

1. Start Date and Time of event:

   The storm began in the morning on Wednesday, November 30, 2020 with scattered interruptions starting at approximately 8:00 a.m. and peaked around 4:20 p.m. on November 30, 2020. The peak reached 36,461 customers interrupted.

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

   The Company secured a total of 272 internal and external field crews to restore power to customers in Rhode Island, consisting of approximately 151 external crews and 121 internal crews. The internal and external field crew numbers 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.

Location	**Crew Type**	**# Crews**
Rhode Island	Internal Overhead Line	122 crews total
	External Overhead Line	131 crews total
	Internal Wire Down	64 crews total
	Internal Transmission	2 crews total
	Internal Underground	22 crews total
	Internal Substation	96 crews total
	Contractor Forestry	116 crews total

4. The first instance of mutual aid coordination:
   Mutual aid was not called for this storm.

5. The first contact with material suppliers:
   The first contact with material suppliers started on November 30, 2020.

6. Inventory levels: Pre-event/Daily/Post-event:

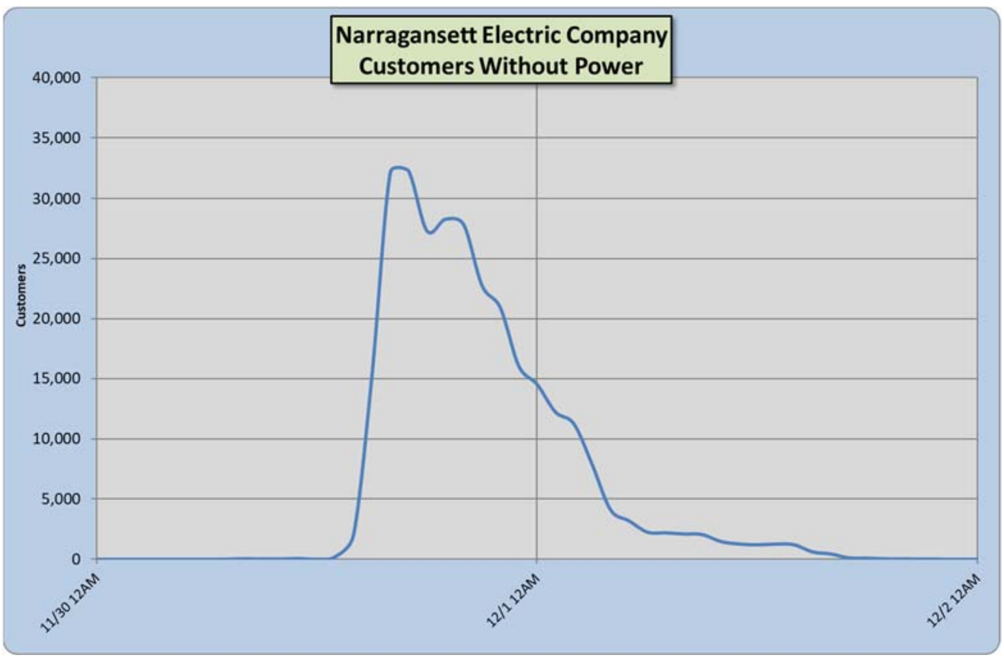
Event Date	RI Inventory Locations	Allocated NEDC Inventory	Total Inventory
11/30/2020	$915,345	$6,760,606	$7,675,951

7. Date/Time of request for External Crews:

   The State Incident Commander for National Grid's Rhode Island was able to obtain sufficient external contractor crews, as well as some Forestry crews from the Company's sister utility in New York, to supplement restoration efforts in New England. No additional assistance was required from companies in the North Atlantic Mutual Assistance Group ("NAMAG") to support restoration for this event.

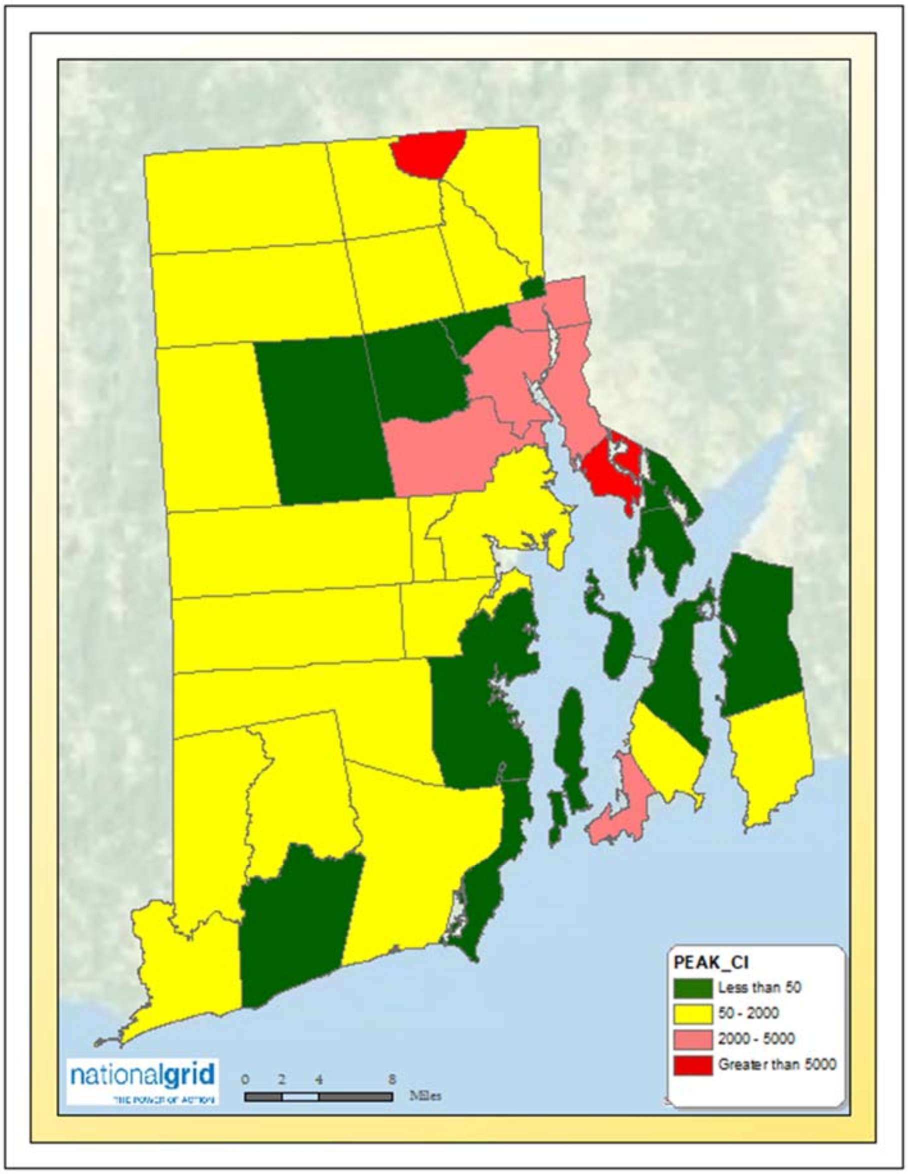
8. Date/Time of external Crews assignment:
   Mutual Assistance was not called for this storm.

9. # of customers out graph (graphs following):

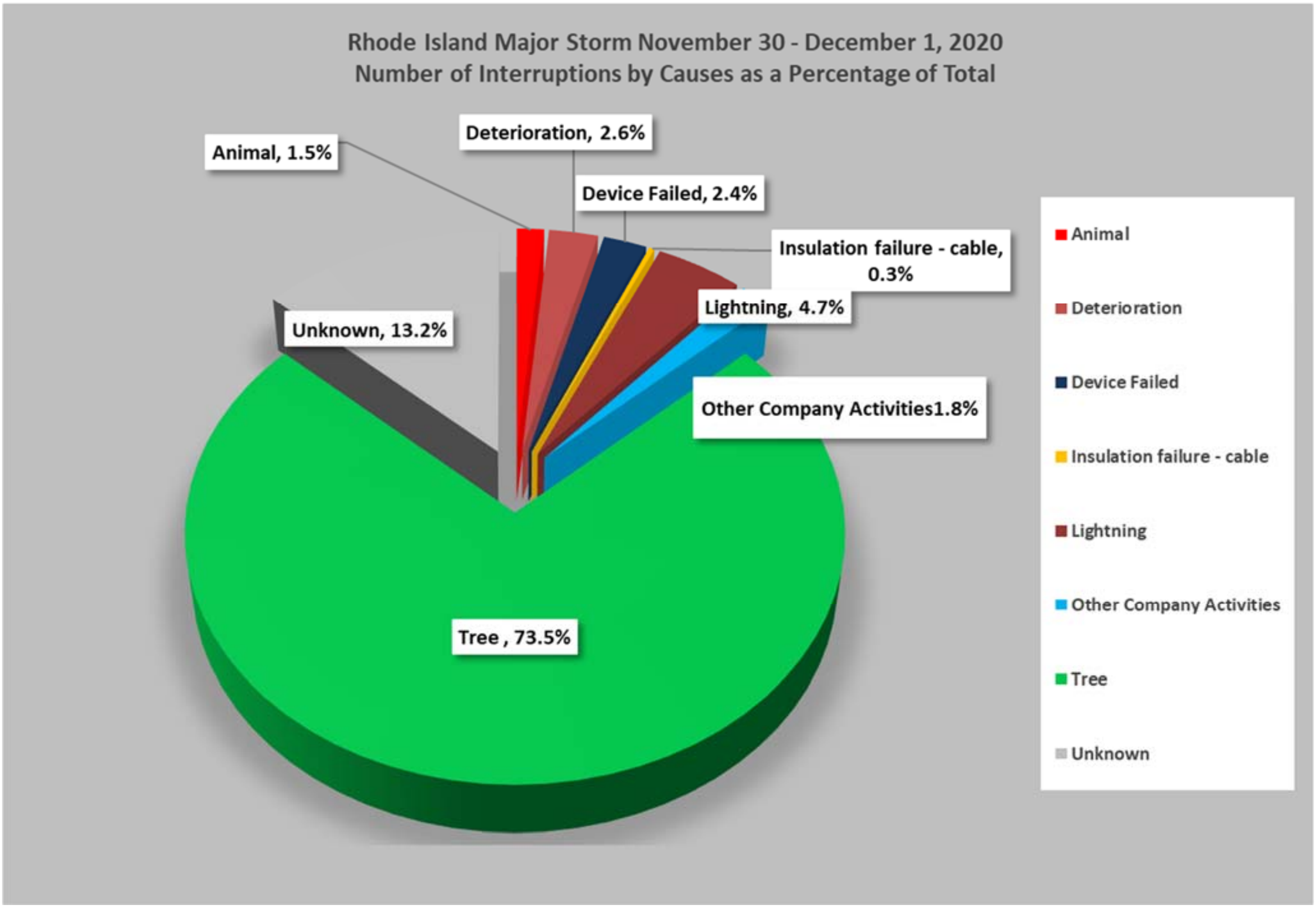


10. Impacted area:

Customer Interrupted by Town at Company Peak
RI 11/30/2020 to 12/01/2020



11. Cause:



12. Weather impact on restoration:
The November 30, 2020 Storm was a significant weather event that resulted in significant damage to the Company's electrical system. The Storm brought a line of thunderstorms with heavy rain and hazardous wind gusts to portions of the Company's service territory. Eastern and especially coastal areas experienced wind gusts in the 45–50 mph range, with Providence experiencing a peak gust of 58 mph. The Towns of Barrington and Exeter were affected most heavily with approximately 98 and 52 percent of their 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, propose and implement a solution. In addition, National Grid undertakes analysis of transmission and substation protection devices and coordination where there is evidence of a mis-operation.

14. Summary of Customers Impacted:

November 30, 2020

During this storm, on November 30, 2020 Rhode Island experienced a total of 211 interruptions that affected 56,284 customers and 17,170,899 customer minutes of interruption. On average these interruptions resulted in 0.113 SAIFI, 34.47 minutes of SAIDI. Since a SAIDI value of 34.47 minutes exceeded the threshold value of 6.03 minutes, November 30, 2020 qualified as a Major Event Day under the IEEE methodology.

December 1, 2020

During this storm, on December 1, 2020 Rhode Island experienced a total of 88 interruptions that affected 3,124 customers and 230,332 customer minutes of interruption. On average these interruptions resulted in 0.0063 SAIFI, 1.35 minutes of SAIDI. Since a SAIDI value of 0.46 minutes is less than the threshold value of 6.03 minutes, December 1, 2020 is not qualified as a Major Event Day under the IEEE methodology.

PRE-FILED DIRECT TESTIMONY

OF

MELISSA A. LITTLE

July 30, 2021

Table of Contents

I. Introduction

Q. Please state your full name and business address.

A. My name is Melissa A. Little, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position.

A. I am a Director for New England Revenue Requirements in the New England Regulation department of National Grid USA Service Company, Inc. (the "Service Company"). The Service Company provides engineering, financial, administrative, and other technical support to subsidiary companies of National Grid USA ("National Grid"). My current duties include revenue requirement responsibilities for National Grid's electric and gas distribution activities in New England, including the electric operations of The Narragansett Electric Company d/b/a National Grid ("Narragansett" or the "Company").

Q. Please describe your education and professional experience.

A. In 2000, I received a Bachelor of Science degree in Accounting Information Systems from Bentley College (now Bentley University). In September 2000, I joined Pricewaterhouse Coopers LLP in Boston, Massachusetts, where I worked as an associate in the Assurance practice. In November 2004, I joined National Grid in the Service Company as an Analyst in the General Accounting group. After the merger of National Grid and KeySpan in 2007, I joined the Regulation and Pricing department as a Senior

Analyst in the Regulatory Accounting function, also supporting the Niagara Mohawk Power Corporation Revenue Requirement team. I was promoted to Lead Specialist in July 2011 and moved to the New England Revenue Requirement team. In August 2017, I was promoted to my current position.

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

A. Yes. Among other testimony, I testified in support of the Company's revenue requirement (1) in the 2017 general rate case filing in Docket No. 4770; (2) in the Fiscal Year 2018 Electric Infrastructure, Safety, and Reliability (ISR) Plan and reconciliation filings in Docket No. 4682, FY 2019 in Docket 4783, FY 2020 in Docket No. 4915, FY 2021 in Docket No. 4995 and FY 2022 in Docket No. 5098; and (3) in the Gas ISR Plan and reconciliation filings for FY 2016 in Docket No. 4540, FY 2017 in Docket No. 4590, FY 2018 in Docket No. 4678, FY 2019 in Docket No. 4781, FY 2020 in Docket No. 4916, FY 2021 in Docket No. 4996, and FY 2022 in Docket No. 5099.

Q. What is the purpose of your testimony?

A. In this docket, the PUC approved a new Electric ISR factor, which went into effect on April 1, 2020. That factor was based on a projected FY 2021 ISR revenue requirement of $32,941,518 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, 2021, on the estimated ISR plant additions during the Company's FYs ended March 31, 2021 and 2020, and on the actual ISR additions during the Company's Fiscal Years ended March 31, 2018 and 2019, 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 my testimony is to present an updated FY 2021 Electric ISR revenue requirement associated with actual FY 2021 O&M programs, the actual capital investment levels for each of FY 2018 through FY 2021 incremental to the level of investment assumed in Docket No. 4770, and actual tax deductibility percentages for FY 2020 capital additions.

At this time, the Company's Tax Department estimates that it will earn taxable income and will utilize prior years' tax net operating losses (NOL) in FY 2021. In Docket No. 4770, the accumulated deferred income taxes included in rate base assumed estimated NOL utilization; therefore, the difference between the new estimated NOL utilization and the NOL utilization assumed in base rates has been included in the vintage year FY 2021 ISR revenue requirement based on this most recent estimate of FY 2021 tax deductibility. Actual tax deductibility percentages for FY 2021 plant additions will not be known until the Company files its FY 2021 income tax return in December of this year. Consequently, the actual tax deductibility percentages for FY 2021 plant additions will be reflected in the Company's FY 2022 Electric ISR Reconciliation filing and will generate a true-up adjustment in that filing.

The updated FY 2021 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, 2021.

As shown on Attachment MAL-1, Page 1 at Line 12, the updated FY 2021 ISR revenue requirement collectible through the Company's ISR factor for the FY 2021 period, including updated tax deductibility adjustments to the FY 2020 revenue requirement, totals $30,717,902. This is a decrease of $2,223,616 from the projected FY 2021 Electric ISR revenue requirement of $32,941,518, previously approved by the PUC in this docket. This decrease is primarily attributable to a decrease in the actual effective FY 2021 property tax rate compared with the projected effective FY 2021 property tax rate in the FY 2021 ISR Plan, partially offset by an increase in the FY 2021 revenue requirement on increased capital investment and corresponding rate base over the estimated amount of capital investment and rate base in the FY 2021 Electric ISR Plan for vintage years FY 2020 and FY2021; and an increase in FY 2021 estimated NOL utilization from the projected FY 2021 NOL utilization.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following Attachments with my testimony:

- Attachment MAL-1 FY 2021 Electric Infrastructure, Safety, and Reliability Plan Reconciliation Revenue Requirement

II. Electric ISR FY2021 Revenue Requirement

Q. Did the Company calculate the updated FY 2021 ISR revenue requirement in the same fashion as calculated in the previous ISR Factor submissions and the August 2020 ISR factor reconciliation?

A. Yes, the Company calculated the FY 2021 Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions. Similar to the FY 2020 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 2020.

The updated FY 2021 ISR revenue requirement calculation is nearly identical to the ISR revenue requirement used to develop the approved ISR factors that became effective April 1, 2020, and as described in previous testimony in this proceeding. I will rely on the testimony included in the Company's FY 2021 ISR Plan for a detailed description of the revenue requirement calculation and will 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 MAL-1.

Q. Please summarize the change in the FY 2021 ISR revenue requirement proposed in this reconciliation filing as compared to the FY 2021 revenue requirement effective April 1, 2020, which was based on projected capital additions approved in the FY 2020 and FY 2021 ISR Plans.

A. As shown in Attachment MAL-1, Page 1, Line 13, column (c), the overall FY 2021 revenue requirement decrease is $2,223,616, which is the net impact of: (1) a $0.9 million increase in the FY 2021 revenue requirement on vintage FY 2020 ISR capital additions mainly driven by the FY 2020 income tax deductibility update and lower retirement of capital investment than anticipated in the FY 2021 Plan, which increases depreciation expense; (2) a $0.2 million increase in the FY 2021 revenue requirement on vintage FY 2021 ISR capital additions mainly caused by $7.0 million higher capital investment placed into service compared to the amount approved in the FY 2021 Plan, (3) a $2,853,000 decrease in the FY 2021 property tax recovery adjustment is mainly driven by the lower actual tax rate in FY 2021 compared to the previous filed FY 2021 Plan, partially offset by higher actual FY 2021 investments and

(4) an increase of $72,443 due to the true-up of FY 2020 revenue requirement to reflect actual tax deductibility as described in detail later in this testimony.

Q. Would you describe the impact on the FY 2021 ISR revenue requirement recoverable through the FY 2021 ISR factor resulting from the implementation of new electric base distribution rates that were approved by the PUC in Docket No. 4770 and put into effect on September 1, 2018?

A. The ISR mechanism was established to allow the Company to recover outside of base rates its costs associated with capital investment incurred to expand its electric infrastructure and improve the reliability and safety of its electric facilities. 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 rate base in that request 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).

Q. How was the Electric ISR revenue requirement revised for the change in the federal income tax rate from 35 percent to 21 percent?

A. The decrease in the federal income tax rate from 35 percent to 21 percent reduced the amount of income tax to be recovered from customers on the return on equity component of each Electric ISR vintage year revenue requirement. The return on rate base in each revenue requirement is calculated by multiplying the Electric ISR rate base times the weighted average cost of capital (WACC). The equity component of the return on rate base is the taxable component of the Electric ISR revenue requirement. The federal income taxes that the Company must recover from customers are derived by grossing up the WACC to a pre-tax rate of return. Consequently, the Company revised the pre-tax WACC to reflect the change in the federal income tax rate. The calculation of the revised pre-tax WACC is shown on Page 22 of Attachment MAL-1.

Q. Were there any other revisions to the Electric ISR revenue requirement that were the result of the change in the federal income tax rate from 35 percent to 21 percent?

A. Yes, effective December 31, 2017, the Company has restated all its deferred tax balances based on the new 21 percent federal income tax rate because the Company is paying income taxes as the book/tax timing differences reverse at that 21 percent federal income tax rate. However, because deferred taxes are an offset to rate base in the Electric ISR revenue requirement, reducing the deferred tax balances based on the 21 percent federal income tax rate has the effect of artificially increasing rate base. To counteract this artificial increase to rate base, a new line item called Excess Deferred Income Taxes has been added to FY 2018 vintage year's revenue requirement calculation reflecting the value of the decrease to ISR rate base as of December 31, 2017. These excess deferred income taxes represent the net benefit as of December 31, 2017 that will eventually be earned by the Company through reduced future income taxes and must ultimately be passed back to customers. The pass back of excess deferred income taxes to customers is fully reflected in base distribution rates under Docket No. 4770 per the Company's Excess Deferred Income Tax True-Up - Second Compliance filing dated May 30, 2019, which the PUC approved on June 17, 2019; therefore, there is no need to adjust the excess deferred tax balance in the ISR revenue requirements.

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 MAL-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 2021 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 2021 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2021 investments.

Q. Are there any updates to the FY 2020 revenue requirement reflected in the FY 2021 Electric ISR Reconciliation?

A. Yes. The Company filed its FY 2020 Electric ISR Reconciliation Compliance Filing on September 30, 2020. However, it had not filed its FY 2020 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 2020 revenue requirement to reflect the following updates on Attachment MAL-1, Pages 10, 11 and 18: (1) actual capital repairs deduction rate of 8.51 percent as shown on Attachment MAL-1, Page 11, Line 2; (2) actual bonus depreciation rate of 3.33 percent as shown on Attachment MAL-1 Page 11, Line 10; (3) actual tax loss on retirements of $2,144,147 as shown on Attachment MAL-1 Page 11, Line 20; and (4) actual NOL utilization of $0 as shown on Attachment MAL-1 Page 18, Line 11, column (c). The net result of these tax deductibility updates is an increase to the FY 2020 ISR revenue requirement of $72,443, as shown on Attachment MAL-1, Page 1 at Line 11.

Q. Please summarize the updated FY 2021 ISR revenue requirement.

A. As shown on Page 1 of Attachment MAL-1, the Company's FY 2021 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 2021 revenue requirement related to O&M expenses of $11,531,947.

As shown on Page 1, at Line 12 of Attachment MAL-1, the FY 2021 revenue requirement associated with the Company's actual capital investment totals $19,185,955.

As previously noted, the total FY 2021 capital investment component of revenue requirement includes (1) FY 2021 revenue requirement on vintages FY 2018 through FY 2021 ISR capital investments above or below the level of capital investment reflected in base distribution rates in Docket No. 4770, (2) the FY 2021 property tax recovery mechanism component, and (3) the FY 2020 revenue requirement true-up for changes to previously estimated tax depreciation expense and NOL position to align with the Company's FY 2020 tax return, which was filed in December 2020. The total actual FY 2021 ISR Plan revenue requirement for both O&M expenses and capital investment of $30,717,902 is shown on Line 13.

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

A. Page 1 of Attachment MAL-1 summarizes the individual components of the updated FY 2021 ISR revenue requirement. Page 1, Column (a) reflects the approved FY 2021 Electric ISR Plan revenue requirement on projected VM and I&M program costs and incremental ISR capital investment as well as the projected FY 2021 property tax recovery adjustment. Page 1, Column (b) represents (1) the O&M components for FY 2021; (2) FY 2021 ISR revenue requirements for incremental FY 2018 through FY 2021 ISR investments – not included in the Company's base rates in Docket No. 4770– and as supported with detailed calculations on Attachment MAL-1, Pages 2 , 5, 10 and 13; (3) FY 2021 property tax adjustment on incremental capital not included in the Company's base rates in Docket No. 4770; and (4) Line 11 reflects the reconciliation of the approved

FY 2020 ISR revenue requirement for vintage FY 2020 plant additions with the actual vintage FY 2020 revenue requirement on those investments. As previously discussed, this reconciliation is necessary because the actual level of tax deductibility on FY 2020 investments was not known when the Company filed the FY 2020 ISR reconciliation and FY 2021 ISR Plan proposals. A detailed calculation of the updated FY 2020 revenue requirement is presented on page 10 of Attachment MAL-1.

Q. Has the Company provided support for the actual level of FY 2021 ISR-eligible plant investments?

A. Yes. The description of the FY 2021 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 2021 totals $116.5 million associated with the Company's FY 2021 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 2021 revenue requirement, the lesser of these items was actual discretionary capital additions of $80,041,254, as shown on Attachment MAL-1, Page 26, Line 13, column (a), of which $80,041,254 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 2021 revenue requirement, associated with the Company's actual FY 2018 through FY 2021 ISR eligible plant investments, totals $30,717,902. This amount includes the updated FY 2021 O&M components and revenue requirement on FY 2018 through FY 2021 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 2020 ISR revenue requirements on vintage FY 2020 investments with the actual FY 2020 income tax deductibility on those investments.

III. <u>Conclusion</u>

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 2021 Annual Revenue Requirement Summary

Line No.		Approved Fiscal Year 2021 (a)	Actual Fiscal Year 2021 (b)	Variance Fiscal Year 2021 (c)= (b)-(a)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$10,600,000	$10,685,641	$85,641
2	Current Year Inspection & Maintenance (I&M)	$1,035,000	$708,167	($326,833)
3	Current Year Other Programs	$456,633	$138,139	($318,494)
4	**Total O&M Expense Component of Revenue Requirement**	**$12,091,633**	**$11,531,947**	**($559,686)**
	Capital Investment:			
5	Actual 2021 Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$2,057,064	$2,057,064	$0
6	Actual 2021 Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$4,272,652	$4,272,646	($6)
7	Actual 2021 Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$5,226,171	$6,119,319	$893,148
8	Actual 2021 Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base	$4,341,988	$4,565,474	$223,485
9	Subtotal	$15,897,876	$17,014,503	$1,116,627
10	FY 2021 Property Tax Recovery Adjustment	$4,952,008	$2,099,008	($2,853,000)
11	True-Up for FY 2020 (Income Tax)		$72,443	$72,443
12	**Total Capital Investment Component of Revenue Requirement**	**$20,849,885**	**$19,185,955**	**($1,663,930)**
13	**Total Fiscal Year Revenue Requirement**	**$32,941,518**	**$30,717,902**	**($2,223,616)**
14	**Incremental Fiscal Year Rate Adjustment**		**($2,223,616)**	

Column/Line Notes:

Col (a)	Docket No. 4995, FY 2021 Electric ISR Plan, **Revised Section 5: Attachment 1R, Page 1 of 25, Column (b)**
Col (b)	
1	Vegetation Management, Section IV of Att. PCE-1, Table 10
2	Other Operations and Maintenance, Section V of Att. PCE-1, Table 11
3	Other Operations and Maintenance, Section V of Att. PCE-1, Table 11
4	Sum of Lines 1 through 3
5	Page 2 of 26, Line 34 column (d)
6	Page 5 of 26, Line 36, Column (c)
7	Page 10 of 26, Line 33, Column (b)
8	Page 13 of 26, Line 34, Column (a)
9	Sum of Lines 5 through 7
10	Page 23 of 26, Line 49, Column (j) × 1,000
11	Page 10 of 26, Line 35, Column (a)
12	Sum of Lines 9 through 11
13	Line 4 + Line 12
14	Line 13 Col (b) - Line 13 Col (a)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
FY 2021 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)
	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 18 of 26, Line 4(a)		$17,816,654	$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
5	Retirements	Page 18 of 26 , Line 10 ,Col (a)		($5,245,072)	$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
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3		$17,816,654	$0	$0	$0
8	Depreciation Expense			$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
10	Cost of Removal	Page 18 of 26 , Line 7 ,Col (a)		$1,719,991	$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**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate		1/	3.40%	3.26%	3.16%	3.16%
13	Vintage Year Tax Depreciation:						
14	2018 Spend	Year 1 = Page 3 of 26, Line 23; then = Page 3 of 26, Column (b)		$13,898,861	$571,028	$528,156	$488,605
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
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12		$392,049	$751,812	$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
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$13,506,812	$13,326,028	$13,125,433	$12,885,287
19	Effective Tax Rate		2/	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
21	Less: FY 2018 Federal NOL	Year 1 = Page 18 of 26 , Line 15 ,Col (a) ; then = Prior Year Line 21		($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
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
	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
25	Accumulated Depreciation	-Line 17		($392,049)	($1,143,862)	($1,872,612)	($2,601,363)
26	Deferred Tax Reserve	-Line 23		($1,262,901)	($1,224,936)	($1,182,811)	($1,132,380)
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
	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)				$16,824,535	$16,142,062
29	Proration Adjustment	Year 1 and Year 2 = 0; Y 3 = Page 4 of 26, Line 41(j)				($1,818)	($2,165)
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29				$16,822,717	$16,139,898
31	Pre-Tax ROR	Page 25 of 26, Line 36				8.23%	8.23%
32	Return and Taxes	Line 30 * Line 31				$1,384,510	$1,328,314
33	Book Depreciation	Line 16				$728,751	$728,751
34	**Annual Revenue Requirement**	Line 32 + Line 33		**N/A**	**N/A**	**$2,113,260**	**$2,057,064**

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 National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY 2018 Incremental Capital Investments

Line No.				Fiscal Year 2018 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 2 of 26, Line 3		$17,816,654	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	9.00%				
					MACR S			
3	Capital Repairs Deduction	Line 1 * Line 2		$1,603,499	basis:	Line 18	$7,910,074	
		`					Annual	Cumulative
	Bonus Depreciation				Fiscal Year		MACRS	Tax Depr
4	Plant Additions	Line 1		$17,816,654	2018	3.750%	$296,628	$13,898,861
5	Less Capital Repairs Deduction	- Line 3		($1,603,499)	2019	7.219%	$571,028	$14,469,889
6	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5		$16,213,155	2020	6.677%	$528,156	$14,998,045
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	2021	6.177%	$488,605	$15,486,650
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$16,213,155	2022	5.713%	$451,903	$15,938,553
9	Bonus depreciation 100% category	100% * 16.38%	2/	16.38%	2023	5.285%	$418,047	$16,356,600
10	Bonus depreciation 50% category	50% * 34.28%	2/	17.14%	2024	4.888%	$386,644	$16,743,245
11	Bonus depreciation 40% category	40% * 44.23%	2/	17.69%	2025	4.522%	$357,694	$17,100,938
12	Bonus depreciation 0% category	0% * 5.11%	2/	0.00%	2026	4.462%	$352,948	$17,453,886
13	Total Bonus Depreciation Rate	Line 9 + Line 10 + Line 11 + Line 12		51.21%	2027	4.461%	$352,868	$17,806,754
14	Bonus Depreciation	Line 8 * Line 13		$8,303,081	2028	4.462%	$352,948	$18,159,702
					2029	4.461%	$352,868	$18,512,570
	Remaining Tax Depreciation				2030	4.462%	$352,948	$18,865,518
15	Plant Additions	Line 1		$17,816,654	2031	4.461%	$352,868	$19,218,386
16	Less Capital Repairs Deduction	Line 3		$1,603,499	2032	4.462%	$352,948	$19,571,334
17	Less Bonus Depreciation	Line 14		$8,303,081	2033	4.461%	$352,868	$19,924,202
18	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 15 - Line 16 - Line 17		$7,910,074	2034	4.462%	$352,948	$20,277,149
19	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	2035	4.461%	$352,868	$20,630,018
20	Remaining Tax Depreciation	Line 18 * Line 19		$296,628	2036	4.462%	$352,948	$20,982,965
					2037	4.461%	$352,868	$21,335,834
21	FY18 Loss incurred due to retirements	Per Tax Department	3/	$1,975,662	2038	2.231%	$176,474	$21,512,308
22	Cost of Removal	Page 2 of 26, Line 10		$1,719,991		100.00%	$7,910,074	
23	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 14, 20, 21, and 22		$13,898,861				

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 National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**		(a) FY20	(b) FY21
1	Book Depreciation	Col (a): Docket 4915, R.S. 3, Att. 1R, page 4 Col (a), Col (b): Docket 4995, R.S. 3, Att. 1R, page 4 Col (b)	$729,805	$728,751
2	Bonus Depreciation		$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): Docket 4915, R.S. 3, Att. 1R, page 4 Col (a), Col (b): Docket 4995, R.S. 3, Att. 1R, page 4 Col (b)	($528,156)	($488,605)
4	FY18 tax (gain)/loss on retirements		$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$201,649	$240,145
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$42,346	$50,431
	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	$42,346	$50,431
15	Net Operating Loss		$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$42,346	$50,431
	Allocation of FY 2018 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration	Line 5	$201,649	$240,145
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	$201,649	$240,145
20	Total FY 2018 Federal NOL			
21	Allocated FY 2018 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20	$0	$0
22	Allocated FY 2018 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	$42,346	$50,431

	Proration Calculation	(h) Number of Days in Month	(i) Proration Percentage	(j) FY20	(k) FY21
26	April	30	91.78%	$3,238.82	$3,857
27	May	31	83.29%	$2,939.11	$3,500
28	June	30	75.07%	$2,649.07	$3,155
29	July	31	66.58%	$2,349.35	$2,798
30	August	31	58.08%	$2,049.64	$2,441
31	September	30	49.86%	$1,759.60	$2,096
32	October	31	41.37%	$1,459.89	$1,739
33	November	30	33.15%	$1,169.84	$1,393
34	December	31	24.66%	$870.13	$1,036
35	January	31	16.16%	$570.42	$679
36	February	28	8.49%	$299.71	$357
37	March	31	0.00%	$0.00	$0
38	Total	365		$19,356	$23,051
39	Deferred Tax Without Proration	Line 25		$42,346	$50,431
40	Average Deferred Tax without Proration	Line 25 * 50%		$21,173	$25,215
41	Proration Adjustment	Line 38 - Line 40		($1,818)	($2,165)

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

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
FY 2021 Revenue Requirement on FY 2019 Actual Incremental Capital Investment

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)
	Capital Investment Allowance					
1	*Non-Discretionary Capital*			$7,452,659		$0
	Discretionary Capital					
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$25,486,776		$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 18 of 26, Line 4(b)		$32,939,435	$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
5	Retirements	Page 18 of 26 , Line 10 ,Col (b)		($10,649,479)	$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
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3, Column (a)		$32,939,435	$0	$0
8	Depreciation Expense			$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
10	Cost of Removal	Page 18 of 26 , 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**
	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%
13	Vintage Year Tax Depreciation:					
14	2019 Spend	Year 1 = Page 6 of 26, Line 22 Then = Page 6 of 26 Column (b)		$9,919,837	$1,842,847	$1,704,487
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
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$710,499	$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
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$9,209,338	$9,674,775	$10,001,852
19	Effective Tax Rate			21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$1,933,961	$2,031,703	$2,100,389
21	Add: FY 2019 Federal NOL incremental utilization	Page 18 of 26 , Line 15 ,Col (b)		$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
	Rate Base Calculation:					
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$33,040,508	$33,040,508	$33,040,508
24	Accumulated Depreciation	-Line 17		($710,499)	($2,087,909)	($3,465,319)
25	Deferred Tax Reserve	-Line 22		($2,925,583)	($3,023,325)	($3,092,011)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$29,404,426	$27,929,274	$26,483,178
	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			$28,666,850	$27,206,226
28	Proration Adjustment	Page 7 of 26, Line 41, Column (j) ~ (l)			$2,587	$3,037
29	Average ISR Rate Base after Deferred Tax Proration	Line 27 + Line 28			$28,669,437	$27,209,264
30	Pre-Tax ROR	Page 25 of 26, Line 36			8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30			$2,359,495	$2,239,322
32	Book Depreciation	Line 16			$1,377,410	$1,377,410
33	Annual Revenue Requirement	Line 31 + Line 32			$3,736,904	$3,616,732
34	Revenue Requirement of Plant	Year 1 = Line 33*7/12, Then = Line 33			$3,736,904	$3,616,732
35	Revenue Requirement of Intangible	Page 8 of 26, Line 30, Column (f)~ (l)			$705,779	$655,914
36	**Revenue Requirement**	Line 34 + Line 35		**N/A**	**$4,442,683**	**$4,272,646**

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 2021 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 26, 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 26, 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

(b)	(c)	(d)	(e)
MACRS basis:	Line 17	$25,527,737	
		Annual	Cumulative
Fiscal Year			
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 National Grid
FY 2021 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) FY20	(b) FY21
1	Book Depreciation	Col (a): Docket 4915, R.S. 3, Att. 1R, page 7 Col (a), Col (b): Docket 4995, R.S. 3, Att. 1R, page 7 Col (b)		$243,233	$1,871,785
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): Docket 4915, R.S. 3, Att. 1R, page 7 Col (a), Col (b): Docket 4995, R.S. 3, Att. 1R, page 7 Col (b)		($537,263)	($2,217,006)
4	FY 2019 tax (gain)/loss on retirements			$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($294,029)	($345,221)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($61,746)	($72,496)
	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	$0
12	Effective Tax Rate			21%	21%
13	Deferred Tax Reserve	Line 11 × Line 12		$0	$0
14	Total Deferred Tax Reserve	Line 7 + Line 13		($61,746)	($72,496)
15	Net Operating Loss			$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($61,746)	($72,496)
	Allocation of FY 2019 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Line 5		($294,029)	($345,221)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		$0	$0
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($294,029)	($345,221)
20	Total FY 2019 Federal NOL			$0	$0
21	Allocated FY 2019 Federal NOL Not Subject to Proration	(Line 18 ÷ Line 19) × Line 20		$0	$0
22	Allocated FY 2019 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		($61,746)	($72,496)
		(h)	(i)	(j)	(k)
	Proration Calculation	Number of Days in Month	Proration Percentage	FY20	FY21
26	April	30	91.80%	($4,724)	($5,546)
27	May	31	83.33%	($4,288)	($5,034)
28	June	30	75.14%	($3,866)	($4,539)
29	July	31	66.67%	($3,430)	($4,028)
30	August	31	58.20%	($2,995)	($3,516)
31	September	30	50.00%	($2,573)	($3,021)
32	October	31	41.53%	($2,137)	($2,509)
33	November	30	33.33%	($1,715)	($2,014)
34	December	31	24.86%	($1,279)	($1,502)
35	January	31	16.39%	($844)	($990)
36	February	29	8.47%	($436)	($512)
37	March	31	0.00%	$0	$0
38	Total	366		($28,286)	($33,211)
39	Deferred Tax Without Proration	Line 25		($61,746)	($72,496)
40	Average Deferred Tax without Proration	Line 39 * 50%		($30,873)	($36,248)
41	Proration Adjustment	Line 38 - Line 40		$2,587	$3,037

Column Notes:
(i) Sum of remaining days in the year (Col (h)) ÷ 365
(j) Current Year Line ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
FY 2021 Revenue Requirement on FY 2019 Intangible Investment

Line No.		Reference	Item 1 (a)	Item 2 (b)	FY19 Total (c) = (a) + (b)	Item 1 (d)	Item 2 (e)	FY 20 Total (f) = (d) + (e)	Item 1 (g)	Item 2 (h)	FY 21 Total (i) = (g) + (h)
	Capital Investment										
1	Start of Rev. Req. Period		09/01/18	09/01/18	09/01/18	04/01/19	04/01/19	04/01/19	04/01/20	04/01/20	04/01/20
2	End of Rev. Req. Period		03/31/19	03/31/19	03/31/19	03/31/20	03/31/20	03/31/20	03/31/21	03/31/21	03/31/21
3	Investment Name	Per Company's Book	Volt-Var Optimization for Lincoln Ope. Center	Volt-Var Optimization IS		Volt-Var Optimization for Lincoln Ope. Center	Volt-Var Optimization IS		Volt-Var Optimization for Lincoln Ope. Center	Volt-Var Optimization IS	
4	Work Order	Per Company's Book	90000194754	90000194755		90000194754	90000194755		90000194754	90000194755	
5	Total Spend		$2,140,000	$1,320,626	$3,460,626	$2,140,000	$1,320,626	$3,460,626	$2,140,000	$1,320,626	$3,460,626
6	In ServiceDate	Per Company's Book	06/19/18	07/11/18		06/19/18	07/11/18		06/19/18	07/11/18	
7	Book AmortizationPeriod	Per Company's Book	84	84		84	84		84	84	
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$2,089,048	$1,289,183	$3,378,230	$1,910,714	$1,179,131	$3,089,845	$1,605,000	$990,470	$2,595,470
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$1,910,714	$1,179,131	$3,089,845	$1,605,000	$990,470	$2,595,470	$1,299,286	$801,809	$2,101,094
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$1,999,881	$1,234,157	$3,234,038	$1,757,857	$1,084,800	$2,842,657	$1,452,143	$896,139	$2,348,282
	Deferred Tax Calculation:										
11	Tax Amortizaton Period	Page 9 of 26	36	36		36	36		36	36	
12	Tax Expensing	Per Tax Department	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Tax Bonus Rate	Per Tax Department	0%	0%		0%	0%		0%	0%	
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 0	$0	$0	$0	$0	$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%)	$713,262	$440,165	$1,153,427	$713,262	$440,165	$1,153,427	$1,664,492	$1,027,183	$2,691,675
16	Ending Acc. Tax Balance	(L. 5 - L. 12- L.14) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$713,262	$440,165	$1,153,427	$1,664,492	$1,027,183	$2,691,675	$1,981,426	$1,222,768	$3,204,194
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$713,262	$440,165	$1,153,427	$1,188,877	$733,674	$1,922,551	$1,822,959	$1,124,975	$2,947,934
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$50,952	$31,443	$82,396	$229,286	$141,496	$370,781	$535,000	$330,157	$865,157
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$229,286	$141,496	$370,781	$535,000	$330,157	$865,157	$840,714	$518,817	$1,359,532
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$140,119	$86,470	$226,589	$382,143	$235,826	$617,969	$687,857	$424,487	$1,112,344
21	Average Book / Tax Timer	Line 17 - Line 20	$573,143	$353,695	$926,838	$806,734	$497,848	$1,304,582	$1,135,102	$700,488	$1,835,590
22	Effective Tax Rate		21%	21%		21%	21%		21%	21%	
23	Deferred Tax Reserve	Line 21 × Line 22	$120,360	$74,276	$194,636	$169,414	$104,548	$273,962	$238,371	$147,103	$385,474
	Rate Base Calculation:										
24	Average Book Balance	Line 10	$1,999,881	$1,234,157	$3,234,038	$1,757,857	$1,084,800	$2,842,657	$1,452,143	$896,139	$2,348,282
25	Deferred Tax Reserve	Line 23	$120,360	$74,276	$194,636	$169,414	$104,548	$273,962	$238,371	$147,103	$385,474
26	Average Rate Base	Line 24 - Line 25	$1,879,521	$1,159,881	$3,039,402	$1,588,443	$980,252	$2,568,695	$1,213,771	$749,037	$1,962,808
	Revenue Requirement Calculation:										
27	Pre-Tax ROR	year 1 = Page 25 of 26, Line 28, column (e)×7÷12 Then = Page 25 of 26, Line 28(e)	4.80%	4.80%		8.23%	8.23%		8.23%	8.23%	
28	Return and Taxes	Line 26 × Line 27	$90,233	$55,684	$145,917	$130,729	$80,675	$211,404	$99,893	$61,646	$161,539
29	Book Depreciation	Line 9 - Line 8	$178,333	$110,052	$288,386	$305,714	$188,661	$494,375	$305,714	$188,661	$494,375
30	Annual Revenue Requirement	Line 28 + Line 29	$268,566	$165,736	$434,302	$436,443	$269,336	$705,779	$405,608	$250,307	$655,914

The Narragansett Electric Company
d/b/a National Grid
FY 2021 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 National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
FY 2021 Revenue Requirement on FY 2020 Actual Incremental Capital Investment

Line No.				Fiscal Year 2020 (a)	Fiscal Year 2021 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*			$32,485,802	$0
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$39,597,335	$0
3	Total Allowed Capital Included in Rate Base	Page 18 of 26, Line 4(c)		$72,083,137	$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
5	Retirements	Page 18 of 26 , Line 10 ,Col (c)		$4,015,632	$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
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$72,083,137	$0
8	Depreciation Expense	Page 22 of 26, Line 41, Col (d) ×7 ÷12		$29,112,370	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$42,970,767	$42,970,767
10	Cost of Removal	Page 18 of 26 , 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**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	Page 20 of 26, Line 3, Col (e)	1/	3.16%	3.16%
13	Vintage Year Tax Depreciation:				
14	2020 Spend	Year 1 = Page 11 of 26, Line 22, Then = Page 11 of 26, Column (d)		$23,811,948	$4,602,526
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$23,811,948	$28,414,474
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,075,467	$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
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$22,736,481	$25,188,074
19	Effective Tax Rate			21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$4,774,661	$5,289,496
21	Add: FY 2020 Federal NOL Utilization	Page 18 of 26, Line 15, Col (c)		($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
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$53,920,323	$53,920,323
24	Accumulated Depreciation	-Line 17		($1,075,467)	($3,226,400)
25	Deferred Tax Reserve	-Line 22		($3,311,681)	($3,826,515)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$49,533,176	$46,867,408
	Revenue Requirement Calculation:				
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 26 * Page 17 of 26, Line 16, Col(e); Then =(Prior Year Line 26 + Current Year Line 26) ÷ 2		$18,516,455	$48,200,292
28	Proration Adjustment	Page 12 of 26, Line 41, Column (j)		$30,912	$18,252
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29		$18,547,368	$48,218,544
30	Pre-Tax ROR	Page 25 of 26, Line 36		8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30		$1,526,448	$3,968,386
32	Book Depreciation	Line 16		$1,075,467	$2,150,933
33	**Annual Revenue Requirement**	Line 31 + Line 32		**$2,601,915**	**$6,119,319**
34	Docket No. 4915, FY 2020 Electric ISR Reconciliation, Page 9, Line 29			$2,529,472	
35	2020 Tax True Up			$72,443	

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 20 of 26, 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)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 10 of 26, Line 3		$72,083,137	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%				
					MACRS			
3	Capital Repairs Deduction	Line 1 * Line 2		$6,134,275	basis:	Line 17	$63,755,733	
							Annual	Cumulative
	Bonus Depreciation				Fiscal Year			
4	Plant Additions	Line 1		$72,083,137	2020	3.750%	$2,390,840	$23,811,948
5	Plant Additions			$0	2021	7.219%	$4,602,526	$28,414,474
6	Less Capital Repairs Deduction	Line 3		$6,134,275	2022	6.677%	$4,256,970	$32,671,444
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$65,948,862	2023	6.177%	$3,938,192	$36,609,636
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	2024	5.713%	$3,642,365	$40,252,001
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$65,948,862	2025	5.285%	$3,369,490	$43,621,491
10	Bonus Depreciation Rate	1 * 14.78% * 30% * 75%	2/	3.33%	2026	4.888%	$3,116,380	$46,737,872
11	Bonus Depreciation Rate	1 * 0% * 25%		0.00%	2027	4.522%	$2,883,034	$49,620,906
12	Total Bonus Depreciation Rate	Line 10 + Line 11		3.33%	2028	4.462%	$2,844,781	$52,465,687
13	Bonus Depreciation	Line 9 * Line 12		$2,193,129	2029	4.461%	$2,844,143	$55,309,830
					2030	4.462%	$2,844,781	$58,154,611
	Remaining Tax Depreciation				2031	4.461%	$2,844,143	$60,998,754
14	Plant Additions	Line 1		$72,083,137	2032	4.462%	$2,844,781	$63,843,535
15	Less Capital Repairs Deduction	Line 3		$6,134,275	2033	4.461%	$2,844,143	$66,687,678
16	Less Bonus Depreciation	Line 13		$2,193,129	2034	4.462%	$2,844,781	$69,532,459
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$63,755,733	2035	4.461%	$2,844,143	$72,376,602
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	2036	4.462%	$2,844,781	$75,221,383
19	Remaining Tax Depreciation	Line 17 * Line 18		$2,390,840	2037	4.461%	$2,844,143	$78,065,526
					2038	4.462%	$2,844,781	$80,910,307
20	FY20 Loss incurred due to retirements	Per Tax Department	3/	$2,144,147	2038	4.461%	$2,844,143	$83,754,450
21	Cost of Removal	Page 10 of 26, Line 10		$10,949,557	2039	2.231%	$1,422,390	$85,176,840
						100.00%	$63,755,733	
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$23,811,948				

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

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investment

Line No.	Deferred Tax Subject to Proration			(a) FY20	(b) FY21
1	Book Depreciation	Col (a): Docket 4915, R.S. 3, Att. 1R, page 10 Col (a), Col (b): Docket 4995, R.S. 3, Att. 1R, page 10 Col (b)		$826,941	$1,651,493
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	Col (a): Docket 4915, R.S. 3, Att. 1R, page 10 Col (a), Col (b): Docket 4995, R.S. 3, Att. 1R, page 10 Col (b)		($2,022,961)	($3,726,100)
4	FY 2020 tax (gain)/loss on retirements	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0		($1,998,280)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($3,194,300)	($2,074,607)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($670,803)	($435,667)
	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		($17,666,783)	
9	Cost of Removal	Year 1 = Docket no. 4915, R.S. 3, Att. 1R, page 10 Col (a); then = 0		($10,562,075)	
10	Book/Tax Depreciation Timing Difference at 3/31/2020			$0	
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		($28,228,858)	
12	Effective Tax Rate			21.00%	
13	Deferred Tax Reserve	Line 11 * Line 12		($5,928,060)	
14	Total Deferred Tax Reserve	Line 7 + Line 13		($6,598,863)	($435,667)
15	Net Operating Loss	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)		$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($6,598,863)	($435,667)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5		($3,194,300)	
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		($28,228,858)	
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($31,423,157)	
20	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)		($2,962,501)	
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20		($2,661,350)	
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20		($301,151)	
23	Effective Tax Rate			21.00%	
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23		($63,242)	
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($734,045)	($435,667)
		(h)	(i)	(j)	(k)
	Proration Calculation	Number of Days in Month	Proration Percentage		
26	April	30	91.80%	($21,921)	($33,330)
27	May	31	83.33%	($19,898)	($30,255)
28	June	30	75.14%	($17,941)	($27,279)
29	July	31	66.67%	($15,919)	($24,204)
30	August	31	58.20%	($13,896)	($21,129)
31	September	30	50.00%	($43,904)	($18,153)
32	October	31	41.53%	($36,467)	($15,078)
33	November	30	33.33%	($29,269)	($12,102)
34	December	31	24.86%	($21,832)	($9,027)
35	January	31	16.39%	($14,395)	($5,952)
36	February	29	8.47%	($7,437)	($3,075)
37	March	31	0.00%	$0	$0
38	Total	366		($242,879)	($199,582)
39	Deferred Tax Without Proration	Line 25		($734,045)	($435,667)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 17 of 26, Line 16, Col (e); then = Line 39 * 50%		($273,791)	($217,834)
41	Proration Adjustment	Line 38 - Line 40		$30,912	$18,252

Column Notes:
(a) Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)
(i) Sum of remaining days in the year (Col (h)) ÷ 365
(j) Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (j)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
FY 2021 Revenue Requirement on FY 2021 Forecasted Incremental Capital Investment

Line No.				Fiscal Year 2021 (a)
	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
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 18 of 26, Line 4(d)		$116,486,800
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$116,486,800
5	Retirements	Page 18 of 26 , Line 10 ,Col (d)		$21,996,026
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$94,490,774
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3		$116,486,800
8	Depreciation Expense	Page 22 of 26, 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
10	Cost of Removal	Page 18 of 26 , Line 7 ,Col (d)		$11,093,804
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$77,673,683**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	Page 20 of 26, Line 3, Col (e)	1/	3.16%
13	Vintage Year Tax Depreciation:			
14	2020 Spend	Year 1 = Page 14 of 26, Line 22, Column (a), Then = Line Page 14 of 26 , Column (d)		$27,607,692
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$27,607,692
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,492,954
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,492,954
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$26,114,738
19	Effective Tax Rate			21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$5,484,095
21	Add: FY 2020 Federal (NOL) Utilization	Page 18 of 26, Line 15, Col (d)		($3,956,093)
22	Net Deferred Tax Reserve beforee Proration Adjustment	Sum of Lines 20 through 21		$1,528,002
	Rate Base Calculation:			
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$77,673,683
24	Accumulated Depreciation	-Line 17		($1,492,954)
25	Deferred Tax Reserve	-Line 22		($1,528,002)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$74,652,727
	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		$37,326,363
28	Proration Adjustment	Page 16 of 26, Line 41		$6,802
29	Average ISR Rate Base after Deferred Tax Proration	Line 27 + Line 28		$37,333,165
30	Pre-Tax ROR	Page 25 of 26, Line 36		8.23%
31	Return and Taxes	Line 29 * Line 30		$3,072,519
32	Book Depreciation	Line 16		$1,492,954
33	Revenue Requirement of Intangible Assets	Page 15 of 26 Line 30 Column (a) ~ (b)		$0
34	**Annual Revenue Requirement**	**Line 31 + Line 32 + Line 33**		**$4,565,474**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 20 of 26, 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)
	Capital Repairs Deduction			
1	Plant Additions	Page 13 of 26, Line 3(a)		$116,486,800
2	Capital Repairs Deduction Rate	Per Tax Department	1/	10.57%
3	Capital Repairs Deduction	Line 1 * Line 2		$12,312,655
	Bonus Depreciation			
4	Plant Additions	Line 1		$116,486,800
5	Plant Additions			$0
6	Less Capital Repairs Deduction	Line 3		$12,312,655
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$104,174,145
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$0
10	Bonus Depreciation Rate	1 * 14.78% * 75% * 30%		0.00%
11	Bonus Depreciation Rate	1 * 25% * 0%		0.00%
12	Total Bonus Depreciation Rate	Line 10 + Line 11		0.00%
13	Bonus Depreciation	Line 9 * Line 12		$0
	Remaining Tax Depreciation			
14	Plant Additions	Line 1		$116,486,800
15	Less Capital Repairs Deduction	Line 3		$12,312,655
16	Less Bonus Depreciation	Line 13		$0
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$104,174,145
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
19	Remaining Tax Depreciation	Line 17 * Line 18		$3,906,530
20	FY21 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$294,703
21	Cost of Removal	Page 13 of 26, Line 10		$11,093,804
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$27,607,692

20 Year MACRS Depreciation

(b)	(c)	(d)	(e)
MACRS basis:	Line 17	$104,174,145	
		Annual	Cumulative
Fiscal Year			
2021	3.750%	$3,906,530	$27,607,692
2022	7.219%	$7,520,332	$35,128,023
2023	6.677%	$6,955,708	$42,083,731
2024	6.177%	$6,434,837	$48,518,568
2025	5.713%	$5,951,469	$54,470,037
2026	5.285%	$5,505,604	$59,975,640
2027	4.888%	$5,092,032	$65,067,673
2028	4.522%	$4,710,755	$69,778,427
2029	4.462%	$4,648,250	$74,426,678
2030	4.461%	$4,647,209	$79,073,886
2031	4.462%	$4,648,250	$83,722,137
2032	4.461%	$4,647,209	$88,369,345
2033	4.462%	$4,648,250	$93,017,596
2034	4.461%	$4,647,209	$97,664,804
2035	4.462%	$4,648,250	$102,313,055
2036	4.461%	$4,647,209	$106,960,263
2037	4.462%	$4,648,250	$111,608,514
2038	4.461%	$4,647,209	$116,255,722
2039	4.462%	$4,648,250	$120,903,972
2040	4.461%	$4,647,209	$125,551,181
2041	2.231%	$2,324,125	$127,875,306
	100.00%	$104,174,145	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital 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 26	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 25 of 26, Line 28, column (e)×7÷12 Then = Page 25 of 26, Line 28(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 National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
FY 2021 Revenue Requirement on FY 2021 Intangible Investment

Line No.	**Deferred Tax Subject to Proration**		(a) FY21
1	Book Depreciation	Page 13 of 26, Line 16 + (Page 15 of 26, Line 19- Line 18)	$1,492,954
2	Bonus Depreciation	Page 14 of 26, Line 13	$0
3	Remaining MACRS Tax Depreciation	- Page 14 of 26, column (d) - (Page 15 of 26, Line 16- Line 15)	($3,906,530)
4	FY 2021 tax (gain)/loss on retirements	- Page 14 of 26, Line 20	($294,703)
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($2,708,279)
6	Effective Tax Rate		21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($568,739)
	Deferred Tax Not Subject to Proration		
8	Capital Repairs Deduction	- Page 14 of 26, Line 3	($12,312,655)
9	Cost of Removal	- Page 14 of 26, Line 21	($11,093,804)
10	Book/Tax Depreciation Timing Difference at 3/31/2021		$0
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($23,406,459)
12	Effective Tax Rate		21.00%
13	Deferred Tax Reserve	Line 11 * Line 12	($4,915,356)
14	Total Deferred Tax Reserve	Line 7 + Line 13	($5,484,095)
15	Net Operating Loss	- Page 13 of 26, Line 21	$3,956,093
16	Net Deferred Tax Reserve	Line 14 + Line 15	($1,528,002)
	Allocation of FY 2020 Estimated Federal NOL		
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5	($2,708,279)
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($23,406,459)
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($26,114,738)
20	Total FY 2021 Federal NOL (Utilization)	- Page 13 of 26, Line 21 / 21%	$18,838,536
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	$16,884,849
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	$1,953,687
23	Effective Tax Rate		21.00%
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	$410,274
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($158,464)

Line No.	**Proration Calculation**	(h) Number of Days in Month	(i) Proration Percentage	(j)
26	April	30	91.78%	($12,120)
27	May	31	83.29%	($10,998)
28	June	30	75.07%	($9,913)
29	July	31	66.58%	($8,792)
30	August	31	58.08%	($7,670)
31	September	30	49.86%	($6,585)
32	October	31	41.37%	($5,463)
33	November	30	33.15%	($4,378)
34	December	31	24.66%	($3,256)
35	January	31	16.16%	($2,135)
36	February	28	8.49%	($1,122)
37	March	31	0.00%	$0
38	Total	365		($72,431)
39	Deferred Tax Without Proration	Line 25		($158,464)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($79,232)
41	Proration Adjustment	Line 38 - Line 40		$6,802

Column Notes:

(i) Sum of remaining days in the year (Col (h)) ÷ 365

(j) & (k) Current Year Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
ISR Additions April 2020 through March 2021

Line No.	Month No.	Month	FY 2021 Plant Additions (a)	In Rates (b)	Not In Rates (c) = (a) - (b)	Weight for Days (d)	Weighted Average (e) = (d) * (c)	Weight for Not in Rates (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 18 of 26, Line 1(c)
Column(b)=Page 18 of 26, 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
FY 2021 Electric ISR Revenue Requirement Reconciliation
FY 2018 - 2021 Incremental Capital Investment Summary

Line No.			Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)
	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
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
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
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
	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
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
7	Incremental Cost of Removal	Line 5 - Line 6	$1,719,991	$101,073	$10,949,557	$11,093,804
	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
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
10	Incremental Retirements	Line 8 - Line 9	($5,245,072)	($10,649,479)	$4,015,632	$21,996,026
	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	$4,256,486
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	$1,448,199
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 19 of 26, Line 10	($2,998,499)	$991,622	$0	$2,808,287
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
15	Incremental (NOL)/Utilization	Line 13 - Line 14	($2,998,499)	$991,622	($1,462,980)	($3,956,093)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Reconciliation
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(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 2018	FY 2019	FY 2020	FY 2021
3	Total Base Rate Plant DIT Provision						$10,558,267	$3,183,499	($847,583.55)	($548,055)
4	Incremental FY 18	$4,261,399	$4,223,434	$4,181,310	$4,130,879		$4,261,399	($37,965)	($42,125)	($50,431)
5	Incremental FY 19	$0	$2,128,597	$2,305,665	$2,485,863			$2,128,597	$177,068	$180,198
6	Incremental FY 20			$4,774,661	$5,289,496				$4,774,661	$514,834
7	Incremental FY 21				$5,484,095					$5,484,095
8	TOTAL Plant DIT Provision	$4,261,399	$6,352,031	$11,261,635	$17,390,332		$14,819,666	$5,274,131	$4,062,021	$5,580,642
9	Distribution-related NOL						$2,998,499	($991,622)	$0	($2,808,287)
10	Lesser of Distribution-related NOL or DIT Provision						$2,998,499	($991,622)	$0	($2,808,287)

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)
8 Sum of Lines 3 through 7
9 Page 18 of 26, Line 13
10 Lesser of Line 8 or Line 9

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 Syste	$ 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 20 of 26, Line 66 (c)				($1,435,572)
69	Plus: Comm Equipment Depreciation		Page 20 of 26, 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 20 of 26, Line 66 (c)				($1,435,572)
76	Plus: Comm Equipment Depreciation		Page 20 of 26, 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 National Grid
FY 2021 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		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)	($11,374)	$753,611
13	Net Plant	$1,060,397							$1,133,035
14	Property Tax Expense	$32,568							$33,333
15	Effective Prop tax Rate	3.07%							2.94%

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

The Narragansett Electric Company
d/b/a National Grid
FY 2021 ISR Property Tax Recovery Adjustment (continued)
(000s)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Cumulative Increm. ISR Prop. Tax for FY2019 7 months				Cumulative Increm. ISR Prop. Tax for FY2020			Cumulative Increm. ISR Prop. Tax for FY2021		
33	Incremental ISR Additions		$36,400				$72,083			$116,487	
34	Book Depreciation: base allowance on ISR eligible plant		$0				$0			$0	
35	Book Depreciation: current year ISR additions		($999)				($1,075)			($1,493)	
36	COR		$101				$10,950			$11,094	
37	Net Plant Additions		$35,502				$81,957			$126,088	
38	RY Effective Tax Rate		3.28%				3.38%			3.58%	
39	ISR Property Tax Recovery on non-ISR		1.91%								
40	ISR Year Effective Tax Rate	3.23%				3.07%			2.94%		
41	RY Effective Tax Rate	3.28%	-0.05%			3.38%	-0.31%		3.58%	-0.63%	
42	RY Effective Tax Rate 7 mos for FY 2019		-0.03% 7 mos								
43	RY Net Plant times Rate Difference	$930,873	-0.03%	($279)		$902,404	-0.31%	($2,816)	$853,576	* -0.63%	($5,418)
44	Non-ISR plant times rate difference					($2,269)	-0.31%	$7	($4,269)	* -0.63%	$27
45	FY 2018 Net Incremental times rate difference	$18,393	1.88%	$346		$17,664	3.07%	$543	$16,935	* 2.94%	$498
46	FY 2019 Net Incremental times rate difference	$35,502	1.88%	$669		$33,630	3.07%	$1,033	$31,759	* 2.94%	$934
47	FY 2020 Net Incremental times rate difference					$81,957	3.07%	$2,517	$79,806	* 2.94%	$2,348
48	FY 2021 Net Adds times rate difference								$126,088	* 2.94%	$3,709
49	Total ISR Property Tax Recovery			$736				$1,284			$2,099

Line Notes

1(a) - 5(h)	Per Docket No. 4783, FY2019 Rec, Part 2 -Attachment MAL-2, Page 13, Line 1(a)~Line 5(h)
6(a) - 10(h)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 20,
11(a) - 15(a)	6(h) - 10(h)
11(b)	Page 18 of 26, Line 1, Column (d)/1000
11(c)	Per Company's Book
11(d)	Line 11(b) + Line 11(c) ×
11(f), 12(f)	Per Company's Book
11(h)	Line11(a) + 11(d) + 11(f)
12(e)	Per Company's Book
12(g)	Page 18 of 26, Line 5 , Column (d)/1000
12(h)	Line12(a) + 12(e) + 12(f) + 12(g)
13(h)	11(h)-12(h)
14(h)	Per Company's Book
15(h)	Line 14(h) ÷ 13(h)
16(a) - 32(g)	Per Docket No. 4783, FY2019 Rec, Part 2 -Attachment MAL-2, Page 13, Line 6(a)~Line 30(g)
33(a) - 49(c)	Per Docket No. 4915, FY2020 Rec, Part 1 -Attachment MAL-1, Compliance Page 21, Line 28(a)~Line 44(g)
33(e) - 49(g)	Docket No. 5098 Attachment 1(C), Page 26 of 29, 38(a) to 53(c)
33(i)	Page 13 of 26, Line 4(a) ÷1000 + Page 15 of 26, Line 5 (a) ÷ 1000
34(i)	FY20 depreciation is reflected in the NBV at 43(h)
35(i)	- Page 13 of 26, Line 16(a) ÷1000 - Page 15 of 26, Line 29 (a) ÷ 1000

Line Notes

36(i)	Page 13 of 26, Line 10(a) ÷1000
37(i)	Sum of Lines 33(i) through 36(i)
38(i)	Docket No. 4770, R. Rebuttal Att. 1, Sch 7-ELEC, P.2, L 3 (c) / [Sch 6-E, P2, ((L9 - L20) × 5/12+ (L30-L41) × 7/12]
40(h)	=15(h)
41(h)	=38(i)
41(i)	40(h) -41(h)
42(i)	=41(i)
43(h)	=43(e) × 5÷12 + Docket 4770, C. Att. 2, (Sch 6-E, P2, L30 - L41) × 7÷12000
43(i) - 44(i)	=41(i)
45(i) - 48(i)	=40(h)
44(h)	=44(e) -2000
44(j)	44(h) x41(i)
46(h)	46(e) - (Page 5 of 26, Line 16(c) + Page 8 of 26, Line 29(i))/1000
46(j)	46(h) x46(i)
47(h)	=47(e) - (Page 10 of 26, Line 16(b)
47(j)	47(h) x47(i)
48(h)	=37(i)
48(j)	48(h) x48(i)
49(j)	Sum of Lines 43(j) through 48(j)

The Narragansett Electric Company
d/b/a National Grid
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						
22	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
23		Ratio	Rate	Weighted Rate	Taxes	Return
24	Long Term Debt	48.35%	4.62%	2.23%		2.23%
25	Short Term Debt	0.60%	1.76%	0.01%		0.01%
26	Preferred Stock	0.10%	4.50%	0.00%		0.00%
27	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
28		100.00%		6.97%	1.26%	8.23%
29						
30	(d) - Column (c) x 21% divided by (1 - 21%)					
31						
32	FY18 Blended Rate	Line 7(e) x 75% + Line 17(e) x 25%				9.36%
33						
34	FY19 Blended Rate	Line 17 x 5 ÷ 12 + Line 28 x 7 ÷ 12				8.31%
35						
36	FY20 and after Rate	Line 28(e)				8.23%

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Incremental Capital Investment

Line No.			Fiscal Year 2021 (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 2021 Proposed Non-Discretionary Capital Additions	Column (a) Section 2, Chart 10, Col 2, Column (b) - Refer to Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (i) + Column (l).	**$36,445,546**	**$0**	$36,445,546
	Discretionary Capital				
2	Cumulative FY 2020 Discretionary Capital ADDITIONS	Docket No. 4915 -ISR Plan Reconciliation	$390,879,667		
3	FY 2021 Discretionary Capital ADDITIONS	Section 2, Chart 10, Col 2	$80,041,254		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$470,920,921		
5	Cumulative FY 2020 Discretionary Capital SPENDING	Docket No. 4915 -ISR Plan Reconciliation	$439,634,859		
6	FY 2021 Discretionary Capital SPENDING	Section 2, Chart 10, Col 1	$59,146,581		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$498,781,440		
8	Cumulative FY 2020 Approved Discretionary Capital SPENDING	Docket No. 4915 -ISR Plan Reconciliation	$425,481,536		
9	FY 2021 Approved Discretionary Capital SPENDING	Section 2, Chart 10, Col 1	$64,845,000		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$490,326,536		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$470,920,921		
12	Prior Year Cumulative Allowed Disretionary Capital Included in Rate Base	Docket No. 4915 -ISR Plan Reconciliation	$390,879,667		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$80,041,254**	**$0**	**$80,041,254**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$116,486,800**	**$0**	**$116,486,800**
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			**$116,486,800**

PRE-FILED DIRECT TESTIMONY

OF

DANIEL E. GALLAGHER

July 30, 2021

Table of Contents

I. Introduction and Qualifications

Q. Please state your full name and business address.

A. My name is Daniel E. Gallagher, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. My position is Senior Analyst, New England Electric Pricing, in the New England Regulation department of National Grid USA Service Company, Inc. ("National Grid"). This department provides rate-related support to The Narragansett Electric Company d/b/a National Grid (the "Company").

Q. Please describe your educational background and training.

A. I earned a Bachelor of Science in Accounting from Framingham State University in 2013.

Q. Please describe your professional experience.

A. In October 2015, I began my career as a pricing analyst at Granite Telecommunications in Quincy, Massachusetts. In June 2016, I was promoted to pricing analyst II. My responsibilities included auditing customer accounts and maintaining the pricing and billing databases to ensure accuracy. In January 2018, I was hired by National Grid as an Electric Pricing Analyst in the New England Regulation department, performing electric rate analysis for National Grid USA's New England service territory. I was promoted to my current role in May 2021.

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

A. Yes, I provided pre-filed direct testimony in the Company's Fiscal Year 2022 Electric Infrastructure, Safety, and Reliability Plan filing, Docket No. 5098; the annual Revenue Decoupling Mechanism Reconciliation filings for 2020 and 2021, Docket Nos. 5030 and 5157, respectively; the 2021 Residential Assistance Recovery filing, Docket No. 5156; and the 2021 Renewable Energy Growth Factor filing, Docket No. 5164.

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") 2021 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 2021 capital investment ("CapEx") revenue requirement and the Operation and Maintenance ("O&M") expense to the actual revenue billed;
- the status of the recovery of the FY 2019 CapEx reconciliation and the credit of the FY 2019 O&M reconciliation;
- the status of the recovery of the FY 2020 CapEx and O&M reconciliations;
- the calculation of the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2021; 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 2021 CapEx and O&M Reconciliations;
- Section IV presents the results of the FY 2021 CapEx Revenue and the Actual CapEx Revenue Requirement Reconciliation, the calculation of the proposed CapEx Reconciling Factors, and the status of the recovery of the FY 2019 and FY 2020 CapEx net under-recovery reconciliation balances;
- Section V presents the results of the FY 2021 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the status of the credit of the FY 2019 O&M over-recovery reconciliation balance and recovery of the FY 2020 O&M under-recovery reconciliation balance; and

- Section VI presents the rate class bill impact analysis.

III. <u>Summary of FY 2021 Capex and O&M Reconciliations</u>

Q. Please summarize the results of the FY 2021 CapEx and O&M reconciliations.

A. A summary of the results of the FY 2021 CapEx and O&M reconciliations is presented in Attachment DEG-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 cost incurred. The calculation of the revenue requirement is presented in the testimony of Company Witness Melissa A. Little. As reflected in Attachment DEG-1, the result of the CapEx reconciliation is an over-recovery of approximately $2.2 million; the result of the O&M reconciliation is an over-recovery of approximately $0.7 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 and determines 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. 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. Capex Reconciliation and Proposed Capex Reconciling Factors

Q. What is the result of the CapEx reconciliation for FY 2021?

A. The FY 2021 CapEx reconciliation by rate class is presented in Attachment DEG-2, page 1. Line (5) represents the CapEx revenue billed during the period April 1, 2020 through March 31, 2021 of approximately $21.4 million. Line (4) reflects the CapEx revenue requirement on actual cumulative ISR capital investment of approximately $19.2 million. Line (6) identifies the net over-recovery by rate class of the CapEx revenue requirement, which totals approximately $2.2 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 DEG-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 DEG-2, page 1, the allocated FY 2021 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 $2.2 million (Line (6)). The detail of the CapEx revenue billed for each rate class is provided in Attachment DEG-2, page 2.

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

A. The amounts presented on Page 1, Line (7) reflect the final balance of the under-recovery resulting from the FY 2019 CapEx reconciliation. The net recovery of the FY 2019 CapEx reconciliation balance is presented on page 3. Of the $3.6 million net under-recovery for FY 2019 to be recovered from customers via CapEx Reconciling Factors approved by the PUC, the Company recovered $3.8 million from October 1, 2019 through September 30, 2020. The remaining balance is a net over-recovery amount of approximately $0.2 million, as shown on Attachment DEG-2, Page 1, Line (7), Column (a). As described in Docket No. 4682, the Company is including each rate class' residual balance associated with the remaining net over-recovery balance of the FY 2019 deferral as an adjustment to the FY 2021 CapEx reconciliation balance, to ensure the Company does not over-credit or under-credit customers any amounts associated with the FY 2019 Plan.

Q. How is the Company proposing to credit the FY 2021 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 DEG-2, page 1. The over or under-recovery by rate class on Line (8) is divided by each rate class' forecasted kWh deliveries for the period October 1, 2021 through September 30, 2022 on Line (9). The class-specific CapEx Reconciling Factors are shown on Line (10).

Q. Is the Company providing the status of the net under-recovery from the FY 2020 CapEx reconciliation?

A. Yes. The status of the FY 2020 CapEx reconciliation net under-recovery balance is presented in Attachment DEG-2, page 4. As of June 30, 2021, the balance reflects a remaining net under-recovery of approximately $1.4 million, which the Company will continue to recover from customers through September 30, 2021.

Q. How will the Company propose to credit or recover any residual balances as of September 30, 2021?

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 2020 CapEx reconciliation in the FY 2022 ISR Plan Reconciliation Filing and include each rate class' residual balance from the FY 2020 CapEx reconciliation with the balances resulting from the FY 2022 CapEx reconciliation and will propose CapEx Reconciling Factors on the total.

V. <u>O&M Reconciliation and Proposed O&M Reconciling Factor</u>

Q. What is the result of the O&M reconciliation for FY 2021?

A. The O&M reconciliation for FY 2021 is presented in Attachment DEG-3, page 1. Line (1) shows the actual O&M expense for FY 2021 of approximately $11.5 million, which is supported in the testimony of Company Witnesses Ms. Patricia Easterly and Ms. Little. Line (2) shows O&M revenue billed through the O&M Factors from April 1, 2020 through March 31, 2021 of approximately $12.2 million. Line (3) shows the difference of approximately $0.7 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 over-recovery resulting from the FY 2019 O&M reconciliation. The crediting to customers of the over-recovery is presented on page 3. Of the $626,839 over-recovery that formed the basis for the O&M Reconciling Factor approved by the PUC, the Company credited customers $575,517 from October 1, 2019 through September 30, 2020, leaving $51,322 to be credited to customers. As described in Docket No. 4682, the Company is including the residual balance with the FY 2021 O&M reconciliation balance.

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

A. Yes. Attachment DEG-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 DEG-3, page 1. The total amount to be credited to customers of $743,647 on Line (5) is divided by the forecasted kWhs during the period October 1, 2021 through September 30, 2022, on Line (6), resulting in a credit factor of 0.010¢ per kWh on Line (7). Pursuant to the ISR Provision, the O&M Reconciling Factor is a uniform per-kWh factor.

Q. Is the Company providing the status of the under-recovery of the FY 2020 O&M reconciliation?

A. Yes. The status of the balance from the FY 2020 O&M reconciliation is presented in Attachment DEG-3, page 4. As of June 30, 2021, there is a remaining under-recovery balance of approximately $0.1 million, which the Company will continue to recover from customers through September 30, 2021.

Q. How does the Company propose to credit or recover the residual balance at September 30, 2021?

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 2020 O&M reconciliation in the FY 2022 ISR Reconciliation Filing and include the residual balance of the FY 2020 O&M reconciliation with the results of the FY 2022 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 DEG-4. 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 $0.90, or approximately 0.8%, from $108.92 to $108.02.

VII. <u>Summary of Retail Delivery Rates</u>

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 2, 2021, 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, effective October 1, 2021. The Company has also submitted a Renewable Energy ("RE") Growth Factor Filing with proposed factors also effective October 1, 2021. The Company will file a Summary of Retail Delivery Rates tariff reflecting all rates proposed for October 1, 2021 in compliance with the PUC's orders in this proceeding, and the PAF and the RE Growth proceedings.

VIII. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

List of Attachments

Attachment DEG-1

FY 2021 ISR Plan Annual Reconciliation Summary

FY 2021 ISR Plan Annual Reconciliation Summary

		CapEx (a)	O&M (b)	Total (c)
(1)	Actual Revenue Requirement	$19,185,955	$11,531,947	$30,717,902
(2)	Revenue Billed	$21,383,272	$12,224,272	$33,607,544
(3)	Total Over/(Under) Recovery	$2,197,317	$692,325	$2,889,642

(1) Column (a): Attachment MAL-1, Page 1, Line (12), Column (b)
Column (b): Attachment MAL-1, Page 1, Line (4), Column (b)
(2) Column (a): Attachment DEG-2, page 1, Line (5)
Column (b): Attachment DEG-3, page 1, line (2)
(3) Line (2) - Line (1)

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

Attachment DEG-2

CapEx Reconciliations and Proposed CapEx Reconciling Factors

Proposed CapEx Reconciling Factors
For Fiscal Year 2021 ISR Plan
For the Recovery/(Refund) Period October 1, 2021 through September 30, 2022

		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 FY2021 Capital Investment Revenue Requirement	$19,185,955						
(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 FY2021 Capital Investment Revenue Requirement	$19,185,955	$10,651,252	$1,972,715	$3,081,143	$3,257,193	$218,182	$5,470
(5)	CapEx Revenue Billed	$21,383,272	$12,561,536	$1,848,887	$3,250,994	$3,562,707	$156,845	$2,303
(6)	Total Over/(Under) Recovery for FY 2021	$2,197,317	$1,910,284	($123,828)	$169,851	$305,514	($61,337)	($3,167)
(7)	Remaining Over/(Under) For FY 2019	$206,756	$172,746	$38,005	($29,879)	($16,817)	$36,614	$6,087
(8)	Total Over/(Under) Recovery	$2,404,073	$2,083,030	($85,823)	$139,972	$288,697	($24,723)	$2,920
(9)	Forecasted kWhs - October 1, 2021 through September 30, 2022	6,938,751,539	2,991,319,261	652,715,602	1,132,580,473	2,100,610,877	47,720,501	13,804,825
(10)	Proposed Class-specific CapEx Reconciling Factor Charge/(Credit) per kWh		($0.00069)	$0.00013	($0.00012)	($0.00013)	$0.00051	($0.00021)

(1) per Attachment MAL-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 2021 CapEx Reconciliation
For the Period April 1, 2020 through March 31, 2021
For the Recovery/Refund Period October 1, 2021 through September 30, 2022

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-20	$430,525	$69,988	$360,537	$64,132	$16,493	$47,639	$127,133	$23,192	$103,941	$117,398	$23,141	$94,257
	May-20	$1,011,613	$154,384	$857,229	$159,059	$35,162	$123,897	$299,187	$46,895	$252,292	$313,261	$49,473	$263,788
	Jun-20	$1,059,617	$161,043	$898,574	$162,933	$35,947	$126,986	$314,633	$50,564	$264,069	$354,788	$49,793	$304,995
	Jul-20	$1,584,517	$240,941	$1,343,576	$214,635	$43,793	$170,842	$334,341	$62,126	$272,215	$363,343	$52,770	$310,573
	Aug-20	$1,919,229	$291,850	$1,627,379	$243,311	$48,895	$194,416	$400,309	$72,435	$327,874	$402,802	$54,627	$348,175
	Sep-20	$1,339,532	$203,638	$1,135,894	$203,618	$41,682	$161,936	$348,830	$60,052	$288,778	$357,754	$50,735	$307,019
	Oct-20	$1,046,833	$172,976	$873,857	$183,474	$41,730	$141,744	$339,807	$59,205	$280,602	$348,573	$52,702	$295,871
	Nov-20	$1,035,097	$191,856	$843,241	$168,971	$38,517	$130,454	$301,645	$54,309	$247,336	$328,577	$54,934	$273,643
	Dec-20	$1,178,802	$218,303	$960,499	$191,395	$44,579	$146,816	$332,490	$62,240	$270,250	$337,810	$60,792	$277,018
	Jan-21	$1,408,936	$260,939	$1,147,997	$220,768	$50,100	$170,668	$321,045	$62,360	$258,685	$345,092	$60,713	$284,379
	Feb-21	$1,325,860	$245,579	$1,080,281	$222,099	$50,407	$171,692	$338,327	$65,590	$272,737	$337,725	$60,238	$277,487
	Mar-21	$1,195,499	$221,430	$974,069	$210,427	$49,392	$161,035	$341,417	$65,095	$276,322	$352,307	$61,523	$290,784
(2)	Apr-21	$562,585	$104,182	$458,403	$126,027	$25,265	$100,762	$168,152	$32,259	$135,893	$265,860	$31,142	$234,718
	Total	$15,098,645	$2,537,109	$12,561,536	$2,370,849	$521,962	$1,848,887	$3,967,316	$716,322	$3,250,994	$4,225,290	$662,583	$3,562,707

		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-20	($601)	($6,990)	$6,389	($625)	($668)	$43
	May-20	$3,749	($8,387)	$12,136	($396)	($516)	$120
	Jun-20	$4,428	($8,104)	$12,532	($396)	($520)	$124
	Jul-20	($2,795)	($4,643)	$1,848	($755)	($991)	$236
	Aug-20	$3,811	($7,012)	$10,823	($723)	($949)	$226
	Sep-20	($1,151)	($7,145)	$5,994	($716)	($940)	$224
	Oct-20	$7,627	($11,126)	$18,753	($931)	($722)	($209)
	Nov-20	$8,266	($6,474)	$14,740	$273	$106	$167
	Dec-20	$12,580	($6,757)	$19,337	$433	$111	$322
	Jan-21	$12,836	($6,887)	$19,723	$389	$100	$289
	Feb-21	$9,970	($5,217)	$15,187	$405	$104	$301
	Mar-21	$9,866	($6,243)	$16,109	$398	$102	$296
(2)	Apr-21	$2,130	($1,144)	$3,274	$220	$56	$164
	Total	$70,716	($86,129)	$156,845	($2,424)	($4,727)	$2,303

(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
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Fiscal Year 2019 CapEx Reconciliation of Under Recovery
For the Period April 1, 2018 through March 31, 2019
For the Recovery/Refund Period October 1, 2019 through September 30, 2020

		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	($3,609,453)		($2,013,964)		($444,730)		($726,206)		($611,178)
(2)	CapEx Reconciling Factors			$0.00071		$0.00074		$0.00058		$0.00027
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-19	$123,530	87,611,246	$62,204	22,026,389	$16,300	43,654,750	$25,320	79,513,121	$21,469
	Nov-19	$251,616	190,160,577	$135,014	45,648,843	$33,780	90,847,607	$52,692	185,379,242	$50,052
	Dec-19	$303,825	235,983,264	$167,548	52,473,683	$38,831	100,320,108	$58,186	188,052,049	$50,774
	Jan-20	$314,879	282,202,675	$200,364	61,528,845	$45,531	114,468,573	$66,392	85,809,730	$23,169
	Feb-20	$297,756	223,159,014	$158,443	53,883,902	$39,874	98,574,412	$57,173	205,205,156	$55,405
	Mar-20	$295,946	219,366,338	$155,750	55,639,390	$41,173	97,853,006	$56,755	198,762,996	$53,666
	Apr-20	$282,455	222,465,066	$157,950	50,299,441	$37,222	90,241,978	$52,340	193,429,114	$52,226
	May-20	$277,011	217,442,927	$154,384	47,515,698	$35,162	80,854,270	$46,895	183,233,317	$49,473
	Jun-20	$288,723	226,821,420	$161,043	48,577,343	$35,947	87,178,918	$50,564	184,419,383	$49,793
	Jul-20	$393,996	339,353,247	$240,941	59,179,079	$43,793	107,114,514	$62,126	195,444,134	$52,770
	Aug-20	$459,846	411,056,434	$291,850	66,074,159	$48,895	124,888,250	$72,435	202,322,342	$54,627
	Sep-20	$348,022	286,814,634	$203,638	56,327,039	$41,682	103,537,158	$60,052	187,905,951	$50,735
(4)	Oct-20	$178,604	137,438,117	$97,581	33,169,193	$24,545	61,029,946	$35,397	111,857,578	$30,202
(5)	Total	$3,816,209		$2,186,710		$482,735		$696,327		$594,361
(6)	Ending Over/(Under) Recovery	$206,756		$172,746		$38,005		($29,879)		($16,817)

		Lighting S-05/S-06/S-10/S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)
(1)	Beginning Over/(Under) Recovery		$161,927		$24,698
(2)	CapEx Reconciling Factors		($0.00293)		($0.00109)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-19	265,631	($778)	903,427	($985)
	Nov-19	6,085,178	($17,830)	1,919,069	($2,092)
	Dec-19	3,229,324	($9,462)	1,882,372	($2,052)
	Jan-20	6,215,504	($18,211)	2,170,306	($2,366)
	Feb-20	3,672,650	($10,761)	2,181,537	($2,378)
	Mar-20	3,017,926	($8,843)	2,344,364	($2,555)
	Apr-20	5,384,169	($15,776)	1,382,797	($1,507)
	May-20	2,862,459	($8,387)	473,155	($516)
	Jun-20	2,765,974	($8,104)	476,935	($520)
	Jul-20	1,584,710	($4,643)	909,345	($991)
	Aug-20	2,393,154	($7,012)	871,016	($949)
	Sep-20	2,438,433	($7,145)	862,206	($940)
(4)	Oct-20	2,853,430	($8,361)	697,212	($760)
(5)	Total		($125,313)		($18,611)
(6)	Ending Over/(Under) Recovery		$36,614		$6,087

(1) Docket No. 4783, Attachment REP-2 Page 1, Line (8)
(2) Docket No. 4783, Attachment REP-2 Page 1, Line (10)
(3) Prorated for usage on and after October 1, 2019
(4) Prorated for usage prior to October 1, 2020
(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

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Fiscal Year 2020 CapEx 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	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	$0	-	$0	-	$0	-	$0	-	$0
	Aug-21	$0	-	$0	-	$0	-	$0	-	$0
(4)	Sep-21	$0	-	$0	-	$0	-	$0	-	$0
(5)	Total	$3,161,345		$1,806,148		$392,438		$514,937		$493,903
(6)	Ending Over/(Under) Recovery	($1,407,395)		($808,679)		($140,884)		($265,107)		($226,287)

		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	-	$0	-	$0
	Aug-21	-	$0	-	$0
(4)	Sep-21	-	$0	-	$0
(5)	Total		($46,978)		$897
(6)	Ending Over/(Under) Recovery		$34,667		($1,106)

(1) Docket No. 4915, Attachment ASC-2 Compliance, Page 1, line (8)
(2) Docket No. 4915, Attachment ASC-2 Compliance, Page 1, line (10)
(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 National Grid
R.I.P.U.C. Docket No. 4995
FY 2021 Electric Infrastructure, Safety,
and Reliability Plan Reconciliation Filing
Attachment DEG-2
Page 4 of 4

Attachment DEG-3

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2021 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For Fiscal Year 2021 ISR Plan
For the Recovery/(Refund) Period October 1, 2021 through September 30, 2022

(1)	Actual FY 2021 O&M Revenue Requirement	$11,531,947
(2)	O&M Revenue Billed	$12,224,272
(3)	Total Over/(Under) Recovery for FY 2021	$692,325
(4)	Remaining Over/(Under) For FY 2019	$51,322
(5)	Total Over/(Under) Recovery	$743,647
(6)	Forecasted kWhs - October 1, 2021 through September 30, 2022	6,938,751,539
(7)	Proposed O&M Reconciling Factor Charge/(Credit) per kWh	($0.00010)

(1) per Attachment MAL-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 2021 Operations & Maintenance Reconciliation
For the Period April 1, 2020 through March 31, 2021
For the Recovery/Refund Period October 1, 2021 through September 30, 2022

O&M Factor Revenue:

	Month	O&M Revenue (a)	Prior Period Reconciliation Factor Revenue (b)	Base O&M Revenue (c)
(1)	Apr-20	$362,269	($18,772)	$381,041
	May-20	$826,503	($42,591)	$869,094
	Jun-20	$856,713	($44,019)	$900,732
	Jul-20	$1,136,513	($56,287)	$1,192,800
	Aug-20	$1,343,604	($64,608)	$1,408,212
	Sep-20	$1,021,277	($51,031)	$1,072,308
	Oct-20	$912,812	($23,533)	$936,345
	Nov-20	$874,730	$10,301	$864,429
	Dec-20	$990,068	$11,639	$978,429
	Jan-21	$1,107,256	$12,715	$1,094,541
	Feb-21	$1,067,905	$12,433	$1,055,472
	Mar-21	$1,013,660	$11,947	$1,001,713
(2)	Apr-21	$474,988	$5,832	$469,156
	Total	$11,988,298	($235,974)	$12,224,272

(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 2019 O&M Reconciliation of Over Recovery
For the Period April 1, 2018 through March 31, 2019
For the Recovery/Refund Period October 1, 2019 through September 30, 2020

		Total
(1)	Over/(Under) Recovery	$626,839
(2)	O&M Reconciling Factor	($0.00008)

		Total kWhs (a)	Total Revenue (b)
	Oct-19	233,974,563	($18,718)
	Nov-19	520,040,516	($41,603)
	Dec-19	581,940,800	($46,555)
	Jan-20	552,395,633	($44,192)
	Feb-20	586,676,671	($46,934)
	Mar-20	576,984,020	($46,159)
	Apr-20	563,202,565	($45,056)
	May-20	532,381,826	($42,591)
	Jun-20	550,239,973	($44,019)
	Jul-20	703,585,029	($56,287)
	Aug-20	807,605,355	($64,608)
	Sep-20	637,885,421	($51,031)
	Oct-20	347,045,476	($27,764)
(3)	Total	7,193,957,848	($575,517)
(4)	Ending Over/(Under) Recovery		$51,322

(1) Docket No. 4783, Attachment REP-3 page 1, line (5)
(2) Docket No. 4783, Attachment REP-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 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	-	$0
	Aug-21	-	$0
	Sep-21	-	$0
	Oct-21	-	$0
(3)	Total	4,809,304,557	$96,187
(4)	Ending Over/(Under) Recovery		($76,203)

(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)

Attachment DEG-4

Typical Bill Analysis

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-16 Rate Customers

Monthly kWh	Rates Effective July 1, 2021				Proposed Rates Effective October 1, 2021				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage of Customers
	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	
(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	$26.20	$11.44	$1.57	$39.21	$25.94	$11.44	$1.56	$38.94	($0.26)	$0.00	($0.01)	($0.27)	-0.7%	0.0%	0.0%	-0.7%	30.1%
300	$43.43	$22.88	$2.76	$69.07	$42.92	$22.88	$2.74	$68.54	($0.51)	$0.00	($0.02)	($0.53)	-0.7%	0.0%	0.0%	-0.8%	12.9%
400	$54.92	$30.51	$3.56	$88.99	$54.24	$30.51	$3.53	$88.28	($0.68)	$0.00	($0.03)	($0.71)	-0.8%	0.0%	0.0%	-0.8%	11.6%
500	$66.42	$38.14	$4.36	$108.92	$65.56	$38.14	$4.32	$108.02	($0.86)	$0.00	($0.04)	($0.90)	-0.8%	0.0%	0.0%	-0.8%	9.6%
600	$77.91	$45.77	$5.15	$128.83	$76.88	$45.77	$5.11	$127.76	($1.03)	$0.00	($0.04)	($1.07)	-0.8%	0.0%	0.0%	-0.8%	7.7%
700	$89.40	$53.40	$5.95	$148.75	$88.20	$53.40	$5.90	$147.50	($1.20)	$0.00	($0.05)	($1.25)	-0.8%	0.0%	0.0%	-0.8%	19.0%
1,200	$146.85	$91.54	$9.93	$248.32	$144.80	$91.54	$9.85	$246.19	($2.05)	$0.00	($0.08)	($2.13)	-0.8%	0.0%	0.0%	-0.9%	6.8%
2,000	$238.78	$152.56	$16.31	$407.65	$235.36	$152.56	$16.16	$404.08	($3.42)	$0.00	($0.15)	($3.57)	-0.8%	0.0%	0.0%	-0.9%	2.3%

			Rates Effective July 1, 2021	Proposed Rates Effective October 1, 2021	Line Item on Bill
			(s)	(t)	
(1)	Distribution Customer Charge		$6.00	$6.00	Customer Charge
(2)	LIHEAP Enhancement Charge		$0.80	$0.80	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge		$2.16	$2.16	RE Growth Program
(4)	Distribution Charge (per kWh)		$0.04580	$0.04580	
(5)	Operating & Maintenance Expense Charge		$0.00204	$0.00204	
(6)	Operating & Maintenance Expense Reconciliation Factor		$0.00002	($0.00010)	
(7)	CapEx Factor Charge		$0.00544	$0.00544	
(8)	CapEx Reconciliation Factor		$0.00090	($0.00069)	
(9)	Revenue Decoupling Adjustment Factor		($0.00042)	($0.00042)	Distribution Energy Charge
(10)	Pension Adjustment Factor		($0.00073)	($0.00073)	
(11)	Storm Fund Replenishment Factor		$0.00288	$0.00288	
(12)	Arrearage Management Adjustment Factor		$0.00006	$0.00006	
(13)	Performance Incentive Factor		$0.00008	$0.00008	
(14)	Low Income Discount Recovery Factor		$0.00196	$0.00196	
(15)	Long-term Contracting for Renewable Energy Charge		$0.00680	$0.00680	Renewable Energy Distribution Charge
(16)	Net Metering Charge		$0.00436	$0.00436	
(17)	Base Transmission Charge		$0.03454	$0.03454	
(18)	Transmission Adjustment Factor		$0.00074	$0.00074	Transmission Charge
(19)	Transmission Uncollectible Factor		$0.00046	$0.00046	
(20)	Base Transition Charge		($0.00149)	($0.00149)	Transition Charge
(21)	Transition Adjustment		$0.00004	$0.00004	
(22)	Energy Efficiency Program Charge		$0.01143	$0.01143	Energy Efficiency Programs
(23)	Last Resort Service Base Charge		$0.07237	$0.07237	
(24)	LRS Adjustment Factor		($0.00512)	($0.00512)	Supply Services Energy Charge
(25)	LRS Adminstrative Cost Adjustment Factor		$0.00238	$0.00238	
(26)	Renewable Energy Standard Charge		$0.00665	$0.00665	
	Line Item on Bill				
(27)	Customer Charge		$6.00	$6.00	
(28)	LIHEAP Enhancement Charge		$0.80	$0.80	
(29)	RE Growth Program		$2.16	$2.16	
(30)	Transmission Charge	kWh x	$0.03574	$0.03574	
(31)	Distribution Energy Charge	kWh x	$0.05803	$0.05632	
(32)	Transition Charge	kWh x	($0.00145)	($0.00145)	
(33)	Energy Efficiency Programs	kWh x	$0.01143	$0.01143	
(34)	Renewable Energy Distribution Charge	kWh x	$0.01116	$0.01116	
(35)	Supply Services Energy Charge	kWh x	$0.07628	$0.07628	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021
Column (t): Line (6) per Attachment DEG-3, Page 1, Line (7). Line (8) per Attachment DEG-2, Page 1, Line (10), Column (b). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

	Rates Effective July 1, 2021						Proposed Rates Effective October 1, 2021						$ 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
(a)	(b)	(c)	(d) = [(b)+(c)] x-.25	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.25	(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	$25.90	$11.44	($9.34)	$28.00	$1.17	$29.17	$25.65	$11.44	($9.27)	$27.82	$1.16	$28.98	($0.18)	$0.00	($0.01)	($0.19)	-0.6%	0.0%	0.0%	-0.7%	32.1%
300	$42.85	$22.88	($16.43)	$49.30	$2.05	$51.35	$42.33	$22.88	($16.30)	$48.91	$2.04	$50.95	($0.39)	$0.00	($0.01)	($0.40)	-0.8%	0.0%	0.0%	-0.8%	15.4%
400	$54.14	$30.51	($21.16)	$63.49	$2.65	$66.14	$53.46	$30.51	($20.99)	$62.98	$2.62	$65.60	($0.51)	$0.00	($0.03)	($0.54)	-0.8%	0.0%	0.0%	-0.8%	12.5%
500	$65.44	$38.14	($25.90)	$77.68	$3.24	$80.92	$64.58	$38.14	($25.68)	$77.04	$3.21	$80.25	($0.64)	$0.00	($0.03)	($0.67)	-0.8%	0.0%	0.0%	-0.8%	9.6%
600	$76.73	$45.77	($30.63)	$91.87	$3.83	$95.70	$75.70	$45.77	($30.37)	$91.10	$3.80	$94.90	($0.77)	$0.00	($0.03)	($0.80)	-0.8%	0.0%	0.0%	-0.8%	7.2%
700	$88.03	$53.40	($35.36)	$106.07	$4.42	$110.49	$86.83	$53.40	($35.06)	$105.17	$4.38	$109.55	($0.90)	$0.00	($0.04)	($0.94)	-0.8%	0.0%	0.0%	-0.9%	16.4%
1,200	$144.50	$91.54	($59.01)	$177.03	$7.38	$184.41	$142.45	$91.54	($58.50)	$175.49	$7.31	$182.80	($1.54)	$0.00	($0.07)	($1.61)	-0.8%	0.0%	0.0%	-0.9%	5.2%
2,000	$234.86	$152.56	($96.86)	$290.56	$12.11	$302.67	$231.44	$152.56	($96.00)	$288.00	$12.00	$300.00	($2.56)	$0.00	($0.11)	($2.67)	-0.8%	0.0%	0.0%	-0.9%	1.6%

	Rates Effective July 1, 2021	Proposed Rates Effective October 1, 2021	Line Item on Bill
	(w)	(x)	
(1) Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$2.16	$2.16	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04580	$0.04580	
(5) Operating & Maintenance Expense Charge	$0.00204	$0.00204	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00002	$\boxed{(\$0.00010)}$	
(7) CapEx Factor Charge	$0.00544	$0.00544	
(8) CapEx Reconciliation Factor	$0.00090	$\boxed{(\$0.00069)}$	
(9) Revenue Decoupling Adjustment Factor	($0.00042)	($0.00042)	Distribution Energy Charge
(10) Pension Adjustment Factor	($0.00073)	($0.00073)	
(11) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12) Arrearage Management Adjustment Factor	$0.00006	$0.00006	
(13) Performance Incentive Factor	$0.00008	$0.00008	
(14) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15) Long-term Contracting for Renewable Energy Charge	$0.00680	$0.00680	Renewable Energy Distribution Charge
(16) Net Metering Charge	$0.00436	$0.00436	
(17) Base Transmission Charge	$0.03454	$0.03454	
(18) Transmission Adjustment Factor	$0.00074	$0.00074	Transmission Charge
(19) Transmission Uncollectible Factor	$0.00046	$0.00046	
(20) Base Transition Charge	($0.00149)	($0.00149)	Transition Charge
(21) Transition Adjustment	$0.00004	$0.00004	
(22) Energy Efficiency Program Charge	$0.01143	$0.01143	Energy Efficiency Programs
(23) Last Resort Service Base Charge	$0.07237	$0.07237	
(24) LRS Adjustment Factor	($0.00512)	($0.00512)	Supply Services Energy Charge
(25) LRS Adminstrative Cost Adjustment Factor	$0.00238	$0.00238	
(26) Renewable Energy Standard Charge	$0.00665	$0.00665	
Line Item on Bill			
(27) Customer Charge	$6.00	$6.00	
(28) LIHEAP Enhancement Charge	$0.80	$0.80	
(29) RE Growth Program	$2.16	$2.16	
(30) Transmission Charge	$0.03574	$0.03574	
(31) Distribution Energy Charge	$0.05607	$\boxed{\$0.05436}$	
(32) Transition Charge	($0.00145)	($0.00145)	
(33) Energy Efficiency Programs	$0.01143	$0.01143	
(34) Renewable Energy Distribution Charge	$0.01116	$0.01116	
(35) Supply Services Energy Charge	$0.07628	$0.07628	
(36) Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021
Column (x): Line (6) per Attachment DEG-3, Page 1, Line (7). Line (8) per Attachment DEG-2, Page 1, Line (10), Column (b). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

	Rates Effective July 1, 2021						Proposed Rates Effective October 1, 2021						$ 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
(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	$25.90	$11.44	($11.20)	$26.14	$1.09	$27.23	$25.65	$11.44	($11.13)	$25.96	$1.08	$27.04	($0.18)	$0.00	($0.01)	($0.19)	-0.7%	0.0%	0.0%	-0.7%	32.1%
300	$42.85	$22.88	($19.72)	$46.01	$1.92	$47.93	$42.33	$22.88	($19.56)	$45.65	$1.90	$47.55	($0.36)	$0.00	($0.02)	($0.38)	-0.8%	0.0%	0.0%	-0.8%	15.4%
400	$54.14	$30.51	($25.40)	$59.25	$2.47	$61.72	$53.46	$30.51	($25.19)	$58.78	$2.45	$61.23	($0.47)	$0.00	($0.02)	($0.49)	-0.8%	0.0%	0.0%	-0.8%	12.5%
500	$65.44	$38.14	($31.07)	$72.51	$3.02	$75.53	$64.58	$38.14	($30.82)	$71.90	$3.00	$74.90	($0.61)	$0.00	($0.02)	($0.63)	-0.8%	0.0%	0.0%	-0.8%	9.6%
600	$76.73	$45.77	($36.75)	$85.75	$3.57	$89.32	$75.70	$45.77	($36.44)	$85.03	$3.54	$88.57	($0.72)	$0.00	($0.03)	($0.75)	-0.8%	0.0%	0.0%	-0.8%	7.2%
700	$88.03	$53.40	($42.43)	$99.00	$4.13	$103.13	$86.83	$53.40	($42.07)	$98.16	$4.09	$102.25	($0.84)	$0.00	($0.04)	($0.88)	-0.8%	0.0%	0.0%	-0.9%	16.4%
1,200	$144.50	$91.54	($70.81)	$165.23	$6.88	$172.11	$142.45	$91.54	($70.20)	$163.79	$6.82	$170.61	($1.44)	$0.00	($0.06)	($1.50)	-0.8%	0.0%	0.0%	-0.9%	5.2%
2,000	$234.86	$152.56	($116.23)	$271.19	$11.30	$282.49	$231.44	$152.56	($115.20)	$268.80	$11.20	$280.00	($2.39)	$0.00	($0.10)	($2.49)	-0.8%	0.0%	0.0%	-0.9%	1.6%

	Rates Effective July 1, 2021 (w)	Proposed Rates Effective October 1, 2021 (x)	Line Item on Bill
(1) Distribution Customer Charge	$6.00	$6.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$2.16	$2.16	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04580	$0.04580	Distribution Energy Charge
(5) Operating & Maintenance Expense Charge	$0.00204	$0.00204	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00002	($0.00010)	
(7) CapEx Factor Charge	$0.00544	$0.00544	
(8) CapEx Reconciliation Factor	$0.00090	($0.00069)	
(9) Revenue Decoupling Adjustment Factor	($0.00042)	($0.00042)	
(10) Pension Adjustment Factor	($0.00073)	($0.00073)	
(11) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12) Arrearage Management Adjustment Factor	$0.00006	$0.00006	
(13) Performance Incentive Factor	$0.00008	$0.00008	
(14) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15) Long-term Contracting for Renewable Energy Charge	$0.00680	$0.00680	Renewable Energy Distribution Charge
(16) Net Metering Charge	$0.00436	$0.00436	
(17) Base Transmission Charge	$0.03454	$0.03454	Transmission Charge
(18) Transmission Adjustment Factor	$0.00074	$0.00074	
(19) Transmission Uncollectible Factor	$0.00046	$0.00046	
(20) Base Transition Charge	($0.00149)	($0.00149)	Transition Charge
(21) Transition Adjustment	$0.00004	$0.00004	
(22) Energy Efficiency Program Charge	$0.01143	$0.01143	Energy Efficiency Programs
(23) Last Resort Service Base Charge	$0.07237	$0.07237	Supply Services Energy Charge
(24) LRS Adjustment Factor	($0.00512)	($0.00512)	
(25) LRS Adminstrative Cost Adjustment Factor	$0.00238	$0.00238	
(26) Renewable Energy Standard Charge	$0.00665	$0.00665	
Line Item on Bill			
(27) Customer Charge	$6.00	$6.00	
(28) LIHEAP Enhancement Charge	$0.80	$0.80	
(29) RE Growth Program	$2.16	$2.16	
(30) Transmission Charge	$0.03574	$0.03574	
(31) Distribution Energy Charge	$0.05607	$0.05436	
(32) Transition Charge	($0.00145)	($0.00145)	
(33) Energy Efficiency Programs	$0.01143	$0.01143	
(34) Renewable Energy Distribution Charge	$0.01116	$0.01116	
(35) Supply Services Energy Charge	$0.07628	$0.07628	
(36) Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021
Column (x): Line (6) per Attachment DEG-3, Page 1, Line (7). Line (8) per Attachment DEG-2, Page 1, Line (10), Column (b). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to C-06 Rate Customers

	Rates Effective July 1, 2021				Proposed Rates Effective October 1, 2021				$ 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	$41.78	$17.78	$2.48	$62.04	$41.57	$17.78	$2.47	$61.82	($0.21)	$0.00	($0.01)	($0.22)	-0.3%	0.0%	0.0%	-0.4%	56.3%
500	$69.42	$35.56	$4.37	$109.35	$69.00	$35.56	$4.36	$108.92	($0.42)	$0.00	($0.01)	($0.43)	-0.4%	0.0%	0.0%	-0.4%	16.9%
1,000	$124.68	$71.11	$8.16	$203.95	$123.84	$71.11	$8.12	$203.07	($0.84)	$0.00	($0.04)	($0.88)	-0.4%	0.0%	0.0%	-0.4%	8.1%
1,500	$179.95	$106.67	$11.94	$298.56	$178.69	$106.67	$11.89	$297.25	($1.26)	$0.00	($0.05)	($1.31)	-0.4%	0.0%	0.0%	-0.4%	5.0%
2,000	$235.21	$142.22	$15.73	$393.16	$233.53	$142.22	$15.66	$391.41	($1.68)	$0.00	($0.07)	($1.75)	-0.4%	0.0%	0.0%	-0.4%	13.6%

	Rates Effective July 1, 2021 (s)	Proposed Rates Effective October 1, 2021 (t)	Line Item on Bill
(1) Distribution Customer Charge	$10.00	$10.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$3.35	$3.35	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04482	$0.04482	
(5) Operating & Maintenance Expense Charge	$0.00201	$0.00201	
(6) Operating & Maintenance Expense Reconciliation Factor	$0.00002	($0.00010)	
(7) CapEx Factor Charge	$0.00456	$0.00456	
(8) CapEx Reconciliation Factor	$0.00085	$0.00013	
(9) Revenue Decoupling Adjustment Factor	($0.00042)	($0.00042)	Distribution Energy Charge
(10) Pension Adjustment Factor	($0.00073)	($0.00073)	
(11) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12) Arrearage Management Adjustment Factor	$0.00006	$0.00006	
(13) Performance Incentive Factor	$0.00008	$0.00008	
(14) Low Income Discount Recovery Factor	$0.00196	$0.00196	
(15) Long-term Contracting for Renewable Energy Charge	$0.00680	$0.00680	Renewable Energy Distribution Charge
(16) Net Metering Charge	$0.00436	$0.00436	
(17) Base Transmission Charge	$0.03470	$0.03470	
(18) Transmission Adjustment Factor	($0.00179)	($0.00179)	Transmission Charge
(19) Transmission Uncollectible Factor	$0.00039	$0.00039	
(20) Base Transition Charge	($0.00149)	($0.00149)	Transition Charge
(21) Transition Adjustment	$0.00004	$0.00004	
(22) Energy Efficiency Program Charge	$0.01143	$0.01143	Energy Efficiency Programs
(23) Last Resort Service Base Charge	$0.05667	$0.05667	
(24) LRS Adjustment Factor	$0.00568	$0.00568	Supply Services Energy Charge
(25) LRS Adminstrative Cost Adjustment Factor	$0.00211	$0.00211	
(26) Renewable Energy Standard Charge	$0.00665	$0.00665	
Line Item on Bill			
(27) Customer Charge	$10.00	$10.00	
(28) LIHEAP Enhancement Charge	$0.80	$0.80	
(29) RE Growth Program	$3.35	$3.35	
(30) Transmission Charge	$0.03330	$0.03330	
(31) Distribution Energy Charge	$0.05609	$0.05525	
(32) Transition Charge	($0.00145)	($0.00145)	
(33) Energy Efficiency Programs	$0.01143	$0.01143	
(34) Renewable Energy Distribution Charge	$0.01116	$0.01116	
(35) Supply Services Energy Charge	$0.07111	$0.07111	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021
Column (t): Line (6) per Attachment DEG-3, Page 1, Line (7). Line (8) per Attachment DEG-2, Page 1, Line (10), Column (c). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

			Rates Effective July 1, 2021				Proposed Rates Effective October 1, 2021				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use	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
	(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)
20	200	4,000	$531.65	$284.44	$34.00	$850.09	$528.13	$284.44	$33.86	$846.43	($3.52)	$0.00	($0.14)	($3.66)	-0.4%	0.0%	0.0%	-0.4%
50	200	10,000	$1,186.85	$711.10	$79.08	$1,977.03	$1,178.05	$711.10	$78.71	$1,967.86	($8.80)	$0.00	($0.37)	($9.17)	-0.4%	0.0%	0.0%	-0.5%
100	200	20,000	$2,278.85	$1,422.20	$154.21	$3,855.26	$2,261.25	$1,422.20	$153.48	$3,836.93	($17.60)	$0.00	($0.73)	($18.33)	-0.5%	0.0%	0.0%	-0.5%
150	200	30,000	$3,370.85	$2,133.30	$229.34	$5,733.49	$3,344.45	$2,133.30	$228.24	$5,705.99	($26.40)	$0.00	($1.10)	($27.50)	-0.5%	0.0%	0.0%	-0.5%
20	300	6,000	$620.95	$426.66	$43.65	$1,091.26	$615.67	$426.66	$43.43	$1,085.76	($5.28)	$0.00	($0.22)	($5.50)	-0.5%	0.0%	0.0%	-0.5%
50	300	15,000	$1,410.10	$1,066.65	$103.20	$2,579.95	$1,396.90	$1,066.65	$102.65	$2,566.20	($13.20)	$0.00	($0.55)	($13.75)	-0.5%	0.0%	0.0%	-0.5%
100	300	30,000	$2,725.35	$2,133.30	$202.44	$5,061.09	$2,698.95	$2,133.30	$201.34	$5,033.59	($26.40)	$0.00	($1.10)	($27.50)	-0.5%	0.0%	0.0%	-0.5%
150	300	45,000	$4,040.60	$3,199.95	$301.69	$7,542.24	$4,001.00	$3,199.95	$300.04	$7,500.99	($39.60)	$0.00	($1.65)	($41.25)	-0.5%	0.0%	0.0%	-0.5%
20	400	8,000	$710.25	$568.88	$53.30	$1,332.43	$703.21	$568.88	$53.00	$1,325.09	($7.04)	$0.00	($0.30)	($7.34)	-0.5%	0.0%	0.0%	-0.6%
50	400	20,000	$1,633.35	$1,422.20	$127.31	$3,182.86	$1,615.75	$1,422.20	$126.58	$3,164.53	($17.60)	$0.00	($0.73)	($18.33)	-0.6%	0.0%	0.0%	-0.6%
100	400	40,000	$3,171.85	$2,844.40	$250.68	$6,266.93	$3,136.65	$2,844.40	$249.21	$6,230.26	($35.20)	$0.00	($1.47)	($36.67)	-0.6%	0.0%	0.0%	-0.6%
150	400	60,000	$4,710.35	$4,266.60	$374.04	$9,350.99	$4,657.55	$4,266.60	$371.84	$9,295.99	($52.80)	$0.00	($2.20)	($55.00)	-0.6%	0.0%	0.0%	-0.6%
20	500	10,000	$799.55	$711.10	$62.94	$1,573.59	$790.75	$711.10	$62.58	$1,564.43	($8.80)	$0.00	($0.36)	($9.16)	-0.6%	0.0%	0.0%	-0.6%
50	500	25,000	$1,856.60	$1,777.75	$151.43	$3,785.78	$1,834.60	$1,777.75	$150.51	$3,762.86	($22.00)	$0.00	($0.92)	($22.92)	-0.6%	0.0%	0.0%	-0.6%
100	500	50,000	$3,618.35	$3,555.50	$298.91	$7,472.76	$3,574.35	$3,555.50	$297.08	$7,426.93	($44.00)	$0.00	($1.83)	($45.83)	-0.6%	0.0%	0.0%	-0.6%
150	500	75,000	$5,380.10	$5,333.25	$446.39	$11,159.74	$5,314.10	$5,333.25	$443.64	$11,090.99	($66.00)	$0.00	($2.75)	($68.75)	-0.6%	0.0%	0.0%	-0.6%
20	600	12,000	$888.85	$853.32	$72.59	$1,814.76	$878.29	$853.32	$72.15	$1,803.76	($10.56)	$0.00	($0.44)	($11.00)	-0.6%	0.0%	0.0%	-0.6%
50	600	30,000	$2,079.85	$2,133.30	$175.55	$4,388.70	$2,053.45	$2,133.30	$174.45	$4,361.20	($26.40)	$0.00	($1.10)	($27.50)	-0.6%	0.0%	0.0%	-0.6%
100	600	60,000	$4,064.85	$4,266.60	$347.14	$8,678.59	$4,012.05	$4,266.60	$344.94	$8,623.59	($52.80)	$0.00	($2.20)	($55.00)	-0.6%	0.0%	0.0%	-0.6%
150	600	90,000	$6,049.85	$6,399.90	$518.74	$12,968.49	$5,970.65	$6,399.90	$515.44	$12,885.99	($79.20)	$0.00	($3.30)	($82.50)	-0.6%	0.0%	0.0%	-0.6%

	Rates Effective July 1, 2021 (r)	Proposed Rates Effective October 1, 2021 (s)	Line Item on Bill
(1) Distribution Customer Charge	$145.00	$145.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$32.45	$32.45	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)	$1.44	$1.44	
(6) Distribution Charge (per kWh)	$0.00476	$0.00476	Distribution Energy Charge
(7) Operating & Maintenance Expense Charge	$0.00178	$0.00178	
(8) Operating & Maintenance Expense Reconciliation Factor	$0.00002	($0.00010)	
(9) CapEx Reconciliation Factor	$0.00064	($0.00012)	
(10) Revenue Decoupling Adjustment Factor	($0.00042)	($0.00042)	
(11) Pension Adjustment Factor	($0.00073)	($0.00073)	
(12) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13) Arrearage Management Adjustment Factor	$0.00006	$0.00006	
(14) Performance Incentive Factor	$0.00008	$0.00008	
(15) Low Income Discount Recovery Factor	$0.00196	$0.00196	
(16) Long-term Contracting for Renewable Energy Charge	$0.00680	$0.00680	Renewable Energy Distribution Charge
(17) Net Metering Charge	$0.00436	$0.00436	
(18) Transmission Demand Charge	$4.57	$4.57	Transmission Demand Charge
(19) Base Transmission Charge	$0.01401	$0.01401	Transmission Adjustment
(20) Transmission Adjustment Factor	($0.00192)	($0.00192)	
(21) Transmission Uncollectible Factor	$0.00039	$0.00039	
(22) Base Transition Charge	($0.00149)	($0.00149)	Transition Charge
(23) Transition Adjustment	$0.00004	$0.00004	
(24) Energy Efficiency Program Charge	$0.01143	$0.01143	Energy Efficiency Programs
(25) Last Resort Service Base Charge	$0.05667	$0.05667	Supply Services Energy Charge
(26) LRS Adjustment Factor	$0.00568	$0.00568	
(27) LRS Adminstrative Cost Adjustment Factor	$0.00211	$0.00211	
(28) Renewable Energy Standard Charge	$0.00665	$0.00665	
Line Item on Bill			
(29) Customer Charge	$145.00	$145.00	
(31) LIHEAP Enhancement Charge	$0.80	$0.80	
(30) RE Growth Program	$32.45	$32.45	
(32) Transmission Adjustment	$0.01248	$0.01248	
(33) Distribution Energy Charge	$0.01103	$0.01015	
(34) Distribution Demand Charge	$8.34	$8.34	
(35) Transmission Demand Charge	$4.57	$4.57	
(34) Transition Charge	($0.00145)	($0.00145)	
(35) Energy Efficiency Programs	$0.01143	$0.01143	
(36) Renewable Energy Distribution Charge	$0.01116	$0.01116	
(37) Supply Services Energy Charge	$0.07111	$0.07111	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021
Column (s): Line (8) per Attachment DEG-3, Page 1, Line (7). Line (9) per Attachment DEG-2, Page 1, Line (10), Column (d). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

			Rates Effective July 1, 2021				Proposed Rates Effective October 1, 2021				$ 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	$4,101.55	$2,164.80	$261.10	$6,527.45	$4,078.35	$2,164.80	$260.13	$6,503.28	($23.20)	$0.00	($0.97)	($24.17)	-0.4%	0.0%	0.0%	-0.4%
750	200	150,000	$15,298.45	$8,118.00	$975.69	$24,392.14	$15,211.45	$8,118.00	$972.06	$24,301.51	($87.00)	$0.00	($3.63)	($90.63)	-0.4%	0.0%	0.0%	-0.4%
1,000	200	200,000	$20,387.95	$10,824.00	$1,300.50	$32,512.45	$20,271.95	$10,824.00	$1,295.66	$32,391.61	($116.00)	$0.00	($4.84)	($120.84)	-0.4%	0.0%	0.0%	-0.4%
1,500	200	300,000	$30,566.95	$16,236.00	$1,950.12	$48,753.07	$30,392.95	$16,236.00	$1,942.87	$48,571.82	($174.00)	$0.00	($7.25)	($181.25)	-0.4%	0.0%	0.0%	-0.4%
2,500	200	500,000	$50,924.95	$27,060.00	$3,249.37	$81,234.32	$50,634.95	$27,060.00	$3,237.29	$80,932.24	($290.00)	$0.00	($12.08)	($302.08)	-0.4%	0.0%	0.0%	-0.4%
5,000	200	1,000,000	$101,819.95	$54,120.00	$6,497.50	$162,437.45	$101,239.95	$54,120.00	$6,473.33	$161,833.28	($580.00)	$0.00	($24.17)	($604.17)	-0.4%	0.0%	0.0%	-0.4%
7,500	200	1,500,000	$152,714.95	$81,180.00	$9,745.62	$243,640.57	$151,844.95	$81,180.00	$9,709.37	$242,734.32	($870.00)	$0.00	($36.25)	($906.25)	-0.4%	0.0%	0.0%	-0.4%
10,000	200	2,000,000	$203,609.95	$108,240.00	$12,993.75	$324,843.70	$202,449.95	$108,240.00	$12,945.42	$323,635.37	($1,160.00)	$0.00	($48.33)	($1,208.33)	-0.4%	0.0%	0.0%	-0.4%
20,000	200	4,000,000	$407,189.95	$216,480.00	$25,986.25	$649,656.20	$404,869.95	$216,480.00	$25,889.58	$647,239.53	($2,320.00)	$0.00	($96.67)	($2,416.67)	-0.4%	0.0%	0.0%	-0.4%
200	300	60,000	$4,992.35	$3,247.20	$343.31	$8,582.86	$4,957.55	$3,247.20	$341.86	$8,546.61	($34.80)	$0.00	($1.45)	($36.25)	-0.4%	0.0%	0.0%	-0.4%
750	300	225,000	$18,638.95	$12,177.00	$1,284.00	$32,099.95	$18,508.45	$12,177.00	$1,278.56	$31,964.01	($130.50)	$0.00	($5.44)	($135.94)	-0.4%	0.0%	0.0%	-0.4%
1,000	300	300,000	$24,841.95	$16,236.00	$1,711.58	$42,789.53	$24,667.95	$16,236.00	$1,704.33	$42,608.28	($174.00)	$0.00	($7.25)	($181.25)	-0.4%	0.0%	0.0%	-0.4%
1,500	300	450,000	$37,247.95	$24,354.00	$2,566.75	$64,168.70	$36,986.95	$24,354.00	$2,555.87	$63,896.82	($261.00)	$0.00	($10.88)	($271.88)	-0.4%	0.0%	0.0%	-0.4%
2,500	300	750,000	$62,059.95	$40,590.00	$4,277.08	$106,927.03	$61,624.95	$40,590.00	$4,258.96	$106,473.91	($435.00)	$0.00	($18.12)	($453.12)	-0.4%	0.0%	0.0%	-0.4%
5,000	300	1,500,000	$124,089.95	$81,180.00	$8,552.92	$213,822.87	$123,219.95	$81,180.00	$8,516.67	$212,916.62	($870.00)	$0.00	($36.25)	($906.25)	-0.4%	0.0%	0.0%	-0.4%
7,500	300	2,250,000	$186,119.95	$121,770.00	$12,828.75	$320,718.70	$184,814.95	$121,770.00	$12,774.37	$319,359.32	($1,305.00)	$0.00	($54.38)	($1,359.38)	-0.4%	0.0%	0.0%	-0.4%
10,000	300	3,000,000	$248,149.95	$162,360.00	$17,104.58	$427,614.53	$246,409.95	$162,360.00	$17,032.08	$425,802.03	($1,740.00)	$0.00	($72.50)	($1,812.50)	-0.4%	0.0%	0.0%	-0.4%
20,000	300	6,000,000	$496,269.95	$324,720.00	$34,207.92	$855,197.87	$492,789.95	$324,720.00	$34,062.92	$851,572.87	($3,480.00)	$0.00	($145.00)	($3,625.00)	-0.4%	0.0%	0.0%	-0.4%
200	400	80,000	$5,883.15	$4,329.60	$425.53	$10,638.28	$5,836.75	$4,329.60	$423.60	$10,589.95	($46.40)	$0.00	($1.93)	($48.33)	-0.4%	0.0%	0.0%	-0.5%
750	400	300,000	$21,979.45	$16,236.00	$1,592.31	$39,807.76	$21,805.45	$16,236.00	$1,585.06	$39,626.51	($174.00)	$0.00	($7.25)	($181.25)	-0.4%	0.0%	0.0%	-0.5%
1,000	400	400,000	$29,295.95	$21,648.00	$2,122.66	$53,066.61	$29,063.95	$21,648.00	$2,113.00	$52,824.95	($232.00)	$0.00	($9.66)	($241.66)	-0.4%	0.0%	0.0%	-0.5%
1,500	400	600,000	$43,928.95	$32,472.00	$3,183.37	$79,584.32	$43,580.95	$32,472.00	$3,168.87	$79,221.82	($348.00)	$0.00	($14.50)	($362.50)	-0.4%	0.0%	0.0%	-0.5%
2,500	400	1,000,000	$73,194.95	$54,120.00	$5,304.79	$132,619.74	$72,614.95	$54,120.00	$5,280.62	$132,015.57	($580.00)	$0.00	($24.17)	($604.17)	-0.4%	0.0%	0.0%	-0.5%
5,000	400	2,000,000	$146,359.95	$108,240.00	$10,608.33	$265,208.28	$145,199.95	$108,240.00	$10,560.00	$263,999.95	($1,160.00)	$0.00	($48.33)	($1,208.33)	-0.4%	0.0%	0.0%	-0.5%
7,500	400	3,000,000	$219,524.95	$162,360.00	$15,911.87	$397,796.82	$217,784.95	$162,360.00	$15,839.37	$395,984.32	($1,740.00)	$0.00	($72.50)	($1,812.50)	-0.4%	0.0%	0.0%	-0.5%
10,000	400	4,000,000	$292,689.95	$216,480.00	$21,215.42	$530,385.37	$290,369.95	$216,480.00	$21,118.75	$527,968.70	($2,320.00)	$0.00	($96.67)	($2,416.67)	-0.4%	0.0%	0.0%	-0.5%
20,000	400	8,000,000	$585,349.95	$432,960.00	$42,429.58	$1,060,739.53	$580,709.95	$432,960.00	$42,236.25	$1,055,906.20	($4,640.00)	$0.00	($193.33)	($4,833.33)	-0.4%	0.0%	0.0%	-0.5%
200	500	100,000	$6,773.95	$5,412.00	$507.75	$12,693.70	$6,715.95	$5,412.00	$505.33	$12,633.28	($58.00)	$0.00	($2.42)	($60.42)	-0.5%	0.0%	0.0%	-0.5%
750	500	375,000	$25,319.95	$20,295.00	$1,900.62	$47,515.57	$25,102.45	$20,295.00	$1,891.56	$47,289.01	($217.50)	$0.00	($9.06)	($226.56)	-0.5%	0.0%	0.0%	-0.5%
1,000	500	500,000	$33,749.95	$27,060.00	$2,533.75	$63,343.70	$33,459.95	$27,060.00	$2,521.66	$63,041.61	($290.00)	$0.00	($12.09)	($302.09)	-0.5%	0.0%	0.0%	-0.5%
1,500	500	750,000	$50,609.95	$40,590.00	$3,800.00	$94,999.95	$50,174.95	$40,590.00	$3,781.87	$94,546.82	($435.00)	$0.00	($18.13)	($453.13)	-0.5%	0.0%	0.0%	-0.5%
2,500	500	1,250,000	$84,329.95	$67,650.00	$6,332.50	$158,312.45	$83,604.95	$67,650.00	$6,302.29	$157,557.24	($725.00)	$0.00	($30.21)	($755.21)	-0.5%	0.0%	0.0%	-0.5%
5,000	500	2,500,000	$168,629.95	$135,300.00	$12,663.75	$316,593.70	$167,179.95	$135,300.00	$12,603.33	$315,083.28	($1,450.00)	$0.00	($60.42)	($1,510.42)	-0.5%	0.0%	0.0%	-0.5%
7,500	500	3,750,000	$252,929.95	$202,950.00	$18,995.00	$474,874.95	$250,754.95	$202,950.00	$18,904.37	$472,609.32	($2,175.00)	$0.00	($90.63)	($2,265.63)	-0.5%	0.0%	0.0%	-0.5%
10,000	500	5,000,000	$337,229.95	$270,600.00	$25,326.25	$633,156.20	$334,329.95	$270,600.00	$25,205.42	$630,135.37	($2,900.00)	$0.00	($120.83)	($3,020.83)	-0.5%	0.0%	0.0%	-0.5%
20,000	500	10,000,000	$674,429.95	$541,200.00	$50,651.25	$1,266,281.20	$668,629.95	$541,200.00	$50,409.59	$1,260,239.54	($5,800.00)	$0.00	($241.66)	($6,041.66)	-0.5%	0.0%	0.0%	-0.5%
200	600	120,000	$7,664.75	$6,494.40	$589.96	$14,749.11	$7,595.15	$6,494.40	$587.06	$14,676.61	($69.60)	$0.00	($2.90)	($72.50)	-0.5%	0.0%	0.0%	-0.5%
750	600	450,000	$28,660.45	$24,354.00	$2,208.94	$55,223.39	$28,399.45	$24,354.00	$2,198.06	$54,951.51	($261.00)	$0.00	($10.88)	($271.88)	-0.5%	0.0%	0.0%	-0.5%
1,000	600	600,000	$38,203.95	$32,472.00	$2,944.83	$73,620.78	$37,855.95	$32,472.00	$2,930.33	$73,258.28	($348.00)	$0.00	($14.50)	($362.50)	-0.5%	0.0%	0.0%	-0.5%
1,500	600	900,000	$57,290.95	$48,708.00	$4,416.62	$110,415.57	$56,768.95	$48,708.00	$4,394.87	$109,871.82	($522.00)	$0.00	($21.75)	($543.75)	-0.5%	0.0%	0.0%	-0.5%
2,500	600	1,500,000	$95,464.95	$81,180.00	$7,360.21	$184,005.16	$94,594.95	$81,180.00	$7,323.96	$183,098.91	($870.00)	$0.00	($36.25)	($906.25)	-0.5%	0.0%	0.0%	-0.5%
5,000	600	3,000,000	$190,899.95	$162,360.00	$14,719.17	$367,979.12	$189,159.95	$162,360.00	$14,646.67	$366,166.62	($1,740.00)	$0.00	($72.50)	($1,812.50)	-0.5%	0.0%	0.0%	-0.5%
7,500	600	4,500,000	$286,334.95	$243,540.00	$22,078.12	$551,953.07	$283,724.95	$243,540.00	$21,969.37	$549,234.32	($2,610.00)	$0.00	($108.75)	($2,718.75)	-0.5%	0.0%	0.0%	-0.5%
10,000	600	6,000,000	$381,769.95	$324,720.00	$29,437.08	$735,927.03	$378,289.95	$324,720.00	$29,292.08	$732,302.03	($3,480.00)	$0.00	($145.00)	($3,625.00)	-0.5%	0.0%	0.0%	-0.5%
20,000	600	12,000,000	$763,509.95	$649,440.00	$58,872.92	$1,471,822.87	$756,549.95	$649,440.00	$58,582.92	$1,464,572.87	($6,960.00)	$0.00	($290.00)	($7,250.00)	-0.5%	0.0%	0.0%	-0.5%

		Rates Effective July 1, 2021 (r)	Proposed Rates Effective October 1, 2021 (s)	Line Item on Bill
(1)	Distribution Customer Charge	$1,100.00	$1,100.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$267.15	$267.15	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)	$1.39	$1.39	
(6)	Distribution Charge (per kWh)	$0.00430	$0.00430	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00089	$0.00089	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	($0.00010)	
(9)	CapEx Reconciliation Factor	$0.00033	($0.00013)	
(10)	Revenue Decoupling Adjustment Factor	($0.00042)	($0.00042)	
(11)	Pension Adjustment Factor	($0.00073)	($0.00073)	
(12)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13)	Arrearage Management Adjustment Factor	$0.00006	$0.00006	
(14)	Performance Incentive Factor	$0.00008	$0.00008	
(15)	Low Income Discount Recovery Factor	$0.00196	$0.00196	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00680	$0.00680	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.00436	$0.00436	
(18)	Transmission Demand Charge	$4.76	$4.76	Transmission Demand Charge
(19)	Base Transmission Charge	$0.01427	$0.01427	Transmission Adjustment
(20)	Transmission Adjustment Factor	($0.00059)	($0.00059)	
(21)	Transmission Uncollectible Factor	$0.00035	$0.00035	
(22)	Base Transition Charge	($0.00149)	($0.00149)	Transition Charge
(23)	Transition Adjustment	$0.00004	$0.00004	
(24)	Energy Efficiency Program Charge	$0.01143	$0.01143	Energy Efficiency Programs
(25)	Last Resort Service Base Charge	$0.05144	$0.05144	Supply Services Energy Charge
(26)	LRS Adjustment Factor	($0.00598)	($0.00598)	
(27)	LRS Adminstrative Cost Adjustment Factor	$0.00201	$0.00201	
(28)	Renewable Energy Standard Charge	$0.00665	$0.00665	
	Line Item on Bill			
(29)	Customer Charge	$1,100.00	$1,100.00	
(30)	LIHEAP Enhancement Charge	$0.80	$0.80	
(31)	RE Growth Program	$267.15	$267.15	
(32)	Transmission Adjustment	$0.01403	$0.01403	
(33)	Distribution Energy Charge	$0.00937	$0.00879	
(34)	Distribution Demand Charge	$6.69	$6.69	
(35)	Transmission Demand Charge	$4.76	$4.76	
(34)	Transition Charge	($0.00145)	($0.00145)	
(35)	Energy Efficiency Programs	$0.01143	$0.01143	
(36)	Renewable Energy Distribution Charge	$0.01116	$0.01116	
(37)	Supply Services Energy Charge	$0.05412	$0.05412	

Column (r): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021

Column (s): Line (8) per Attachment DEG-3, Page 1, Line (7). Line (9) per Attachment DEG-2, Page 1, Line (10), Column (e). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 7/1/2021, and Summary of Rates Last Resort Service tariff, R.I.P.U.C. No. 2096, effective 7/1/2021