The Narragansett Electric Company
d/b/a National Grid

Electric Infrastructure, Safety, and Reliability Plan FY 2022 Proposal

Book 1 of 2

December 21, 2020

Docket No. 5098

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Filing Letter

nationalgrid

Andrew S. Marcaccio
Senior Counsel

December 21, 2020

VIA ELECTRONIC MAIL

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

RE: National Grid's Proposed FY 2022 Electric Infrastructure, Safety, and Reliability Plan Docket No. 5098

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed[1], please see the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the "Electric ISR Plan" or "Plan") for fiscal year ("FY") 2022 for review by the Public Utilities Commission ("Commission"). This Electric ISR Plan is being filed in accordance with R.I. Gen. Laws § 39-1-27.7.1(d).

In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the enclosed Plan addresses (i) capital spending on electric infrastructure; (ii) operation and maintenance ("O&M") expenses on vegetation management; (iii) O&M expenses on system inspection; and (iv) other costs related to maintaining the safety and reliability of the electric distribution system ("Other O&M"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(c)(2), the enclosed Plan also addresses revenue requirement, rate design and bill impacts.

On October 2, 2020, the Company submitted an earlier version of the enclosed Electric ISR Plan to the Division of Public Utilities and Carriers ("Division"). In accordance with R.I. Gen. Laws § 39-1-27.7.1(d), the Division worked in cooperation with the Company to reach an agreement on a proposed plan to be filed with the Commission. Specifically, the Company consulted with the Division's representatives and received and responded to discovery requests from the Division. As a result of this process, the earlier version of the Plan was refined resulting in the enclosed Electric ISR Plan. The Division has indicated general concurrence with the enclosed Electric ISR Plan.

In support of the Electric ISR Plan, the Company has included joint pre-filed direct testimony of Patricia C. Easterly, Ryan A. Moe, And Caitlin Broderick. As explained in their joint testimony, the Company is proposing spending of $103.7 million of capital investment (approved FY 2021 was $103.8 million); $10.8 million of vegetation management O&M spending (approved

[1] 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 an original and five hard copies filed with the Clerk within 24 hours of the electronic filing.

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FY 2021 was $10.6 million); and $1.2 million of Other O&M spending (approved FY 2021 was $1.5 million). Their joint testimony also explains the Company's application of the Docket 4600 goals and framework.

The Company's FY 2022 Electric ISR Plan cumulative revenue requirement is $41,443,447 (approved FY 2021 was $32,941,518). The Company has included pre-filed direct testimony of Melissa A. Little which describes the calculation of the Company's revenue requirement for FY 2022.

For a residential customer receiving Standard Offer Service ("SOS")[2], and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $1.12, or 0.9%. The Company has included pre-filed direct testimony of Daniel E. Gallagher to describe the customer bill impacts of the proposed rate changes.

The Company respectfully requests that the Commission approve the enclosed Electric ISR Plan as filed.

Thank you for your attention to this transmittal. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5098 Service List
John Bell, Division
Greg Booth, Division
Christy Hetherington, Esq.
Al Contente, Division

[2] Effective January 1, 2021, SOS will be replaced by Last Resort Service ("LRS").

Joint Testimony of
Easterly, Moe & Broderick

JOINT PRE-FILED DIRECT TESTIMONY

OF

PATRICIA C. EASTERLY

RYAN A. MOE

CAITLIN BRODERICK

December 21, 2020

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I. INTRODUCTION

Patricia C. Easterly

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

A. My name is Patricia Easterly. My business address is 40 Sylvan Road, Waltham, MA 02451.

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

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

Q. 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 National Grid 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, and Director Rhode Island – New Energy Solutions Planning, Budget and Performance, and Director for Finance Performance Management program. In September of 2018, I assumed my current position as Director – New England Electric Performance and Planning.

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

A. Yes. I have previously testified before the Rhode Island Public Utilities Commission in support of the Company's FY2020 ISR plan and Rhode Island affiliate's Storm Contingency Fund. In addition, I have participated in and managed the Electric ISR negotiations with the Rhode Island Division of Public Utilities and Carriers (Division).

<u>Ryan A. Moe</u>

Q. Mr. Moe, please state your name and business address.

A. My name is Ryan A. Moe. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Mr. Moe, by whom are you employed and in what position?

A. I am employed by National Grid as a Lead Specialist in Vegetation Strategy. In this role, I am responsible for supporting the design and long-term planning of vegetation strategies used on National Grid USA's distribution and sub-transmission assets. I have also provided support for regulatory reporting in Rhode Island.

Q. Mr. Moe, please describe your educational background and professional experience.

A. In 2006, I graduated from the University at Buffalo with a bachelor's degree in Environmental Design. In September 2008, I began working for National Grid's Real Estate department. While in the Company's Real Estate department, my responsibilities included mapping the Company's property records along the transmission lines and analyzing vegetation management rights. In February 2012, I began my current position as a Vegetation Specialist.

Q. Have you previously testified before the Commission?

A. Yes. I have testified before the Commission regarding the vegetation management component of the Electric ISR Plan for FY 2015, 2016, 2017, 2018, 2019, 2020, and 2021 in Docket Nos. 4473, 4529, 4592, 4682, 4783, 4915 and 4995, respectively. I have also provided support for Electric ISR Vegetation Management reporting since March of 2012.

<u>Caitlin Broderick</u>

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

A. My name is Caitlin Broderick. My business address is 280 Melrose Street, Providence, RI 02907.

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

A. I am employed by National Grid as an Engineering Manager in the Distribution Planning and Asset Management Department. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

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

A. In 2013, I graduated from Lehigh University with a Bachelor of Science Degree in Electrical Engineering. In the same year, I was employed by National Grid as an Associate Engineer in the New York Distribution Planning & Asset Management team responsible for the New York Central area. In 2014, I was promoted to Engineer and joined the New England Distribution Planning and Engineering department responsible for long term planning for the North Shore area of Massachusetts. In these roles, I was responsible for identifying asset, capacity and reliability issues, justifying proposed solutions, and initiating selected projects for Operations and Substation engineering departments. I also reviewed and recommended solutions to serve customers requiring significant demand. In 2016, I completed my Master of Engineering degree in Electrical and Computer Engineering at Worcester Polytechnic Institute. In 2017, I was promoted to Senior Engineer in the New England Distribution Planning and Engineering group. In 2018, I joined the National Grid Complex Project Management New England Electric team as a

Lead Project Manager. In this role, I was responsible for managing budget, cost, risk, resources and schedules of complex capital electric projects through detailed design and construction. In March of 2020, I assumed my current position as Manager of Distribution Planning and Asset Management Rhode Island.

Q. Have you previously testified before the Commission?

A. Yes. I have previously testified before the Rhode Island Public Utilities Commission in support of the Company's FY2020 ISR Reconciliation filing in Docket No. 4915.

II. PURPOSE AND STRUCTURE OF JOINT TESTIMONY

Q. What is the purpose of this joint testimony?

A. The purpose of this joint testimony is to present the Fiscal Year 2022 Electric Infrastructure, Safety, and Reliability Plan (the Electric ISR Plan or the Plan), which the Company developed as part of a collaborative process with the Division.[1] As is described in the Plan, implementation of the Electric ISR Plan will allow the Company to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable cost. The proposed Electric ISR Plan is attached as Exhibit 1 to this testimony. In addition, this testimony addresses the goals and Rhode Island benefit-cost

[1] The Electric ISR Plan presented in this filing is the tenth annual plan submitted to the Commission pursuant to the provisions of R.I. Gen. Laws § 39-1-27.7.1.

framework (the Framework)[2] that the Public Utilities Commission (Commission) adopted in its Report and Order No. 22851, dated July 31, 2017 and the Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid, dated October 27, 2017 (the Guidance Document) issued in Docket 4600A to new or incremental programs in the Electric ISR Plan for FY 2022.

Q. How is the testimony structured?

A. In addition to the Introduction and Purpose and Structure of Joint Testimony (Sections I and II, respectively), our joint testimony includes the following sections:

- Description of how the Company developed the Electric ISR Plan and FY 2022 capital investment spending levels (Section III);
- Description of the Company's vegetation management program and FY 2022 spending levels (Section IV);
- Description of the Company's inspection and maintenance (I&M) and other operation and maintenance (Other O&M) programs and FY 2022 spending levels (Section V);
- Application of the Docket 4600 goals and Framework to certain new or incremental programs in the Electric ISR Plan for FY 2022 (Section VI); and
- Conclusion (Section VII).

[2] *See* Appendix B to the Docket 4600 Stakeholder Report (Stakeholder Report), parts of which the Commission adopted in its Report and Order.

Q. Please summarize the categories of infrastructure, safety, and reliability spending covered by the Electric ISR Plan.

A. The proposed Electric ISR Plan addresses the following budget categories for FY 2022, or the twelve-month fiscal year ending March 31, 2022: capital spending on electric infrastructure projects; operation and maintenance (O&M) expenses for vegetation management; O&M for inspection and maintenance (I&M); and O&M for Volt/Var Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion.

Q. Please explain how the Electric ISR Plan is structured.

A. The Electric ISR Plan, which is provided as Exhibit 1 to this testimony, includes the electric infrastructure, safety, and reliability spending plan for FY 2022, and an annual rate reconciliation mechanism that provides for recovery related to capital investments and other spending undertaken pursuant to the annual pre-approved budget for the Electric ISR Plan. The Electric ISR Plan itemizes the recommended work activities by general category and provides budgets for capital investment and O&M expenses for the vegetation management, I&M, and VVO/CVR programs. After the end of the fiscal year, the Company trues up the ISR Plan's projected capital and O&M expense levels used for establishing the revenue requirement to actual or allowed investment and expenditures on a cumulative basis and reconciles the revenue requirement associated with the actual investment and expenditures to the revenue billed from the rate adjustments implemented at the beginning of each fiscal year.

III. CAPITAL INVESTMENT PLAN

Q. How does the Company prepare its capital investment plan?

A. In this filing, the Company has proposed a capital spending plan for FY 2022 totaling $103.7 million. The proposed capital spending plan was developed considering work already underway or identified in the previous 5-year plan as being required to meet system performance and customer requirements, as well as results from area studies, which have been advanced by the annual capacity review process. The project work that is included in the Electric ISR Plan is specifically designed to meet system performance objectives and customer service requirements, which the Company must address as part of its public service obligation to provide safe and reliable service. In the Plan, the Company has provided a detailed explanation of the categories of investment, the factors motivating the nature and amount of investment, and the specific projects that will be undertaken in Rhode Island.

Q. Can you explain the annual capacity review process?

A. Yes. The annual capacity review is a current look at the Company's capacity situation which identifies imminent thermal capacity constraints and assesses the capability of the network to respond to contingencies that might occur. The capacity planning process includes a review of forecasted peak load on each sub-transmission line, substation transformer, and distribution feeder in the entire service territory with a comparison to equipment ratings and consideration of system operational flexibility to respond to various contingency scenarios.

Q. Can you explain how the results from the annual capacity review are used?

A. Yes. When capacity reviews highlight an area that has capacity constraints of a level where a detailed and comprehensive review is warranted, that area is identified as needing an area planning study. Area study priority is determined by assessing the number and severity of electrical issues, with secondary considerations such as the area statistics (complexity) and the date of previous study efforts. The priority is reviewed and adjusted prior to the start of any new study, but at a minimum, at least once a year. Other prompts for an area planning study include the identification of asset condition issues, large new customer load request, or acute reliability issues. Chart 6 in Section 2 of the Plan provides the current status of annual capacity reviews and the prioritization and status of area planning studies. As shown in Chart 6, the Company has completed 100% of the annual capacity reviews in the eleven study areas. The area study planning process is further described in this section of the Plan. The Company has agreed with the Division’s previous recommendation that major projects will progress into the ISR only after completing area planning studies and after such studies have been reviewed by the Division.

Q. What process did the Company undertake to prepare its FY 2022 Electric ISR Plan for review by the Commission?

A. After following the planning processes noted above, the Company prepared the first draft of the Electric ISR Plan, which it submitted to the Division on October 2, 2020 for review pursuant to R.I. Gen. Laws § 39-1-27.7.1 (d). In preparing the capital investment plan, the Company met with the Division and their consultants, Mr. Greg Booth and Ms. Linda Kushner, to discuss the area study and non-wires alternative work being done by the Company, the required pre-filing documentation, and to present an overview of the proposed Plan. The Company also provided an update on its estimating processes supporting the complex capital delivery process with the Division, provided an overview of its load forecasting processes, and provided an overview of the Grid Modernization Plan expected to be filed shortly after the FY 2022 Electric ISR Plan. Subsequently, the Company and the Division met via conference calls to discuss the proposed Plan, and the Company received and responded to data requests from the Division. These negotiations culminated with the Plan being submitted to the Commission with this filing.

Q. Please describe the categories of work activities that are included in the Electric ISR Plan to address service reliability.

A. The Company's overall objective in preparing the Electric ISR Plan is to arrive at a capital spending plan that is the optimal balance in terms of making the investments necessary to improve the performance of discreet aspects of the system, thereby, resulting in maintaining the overall reliability of the system, while also ensuring a cost-effective use of available resources. Therefore, the Plan includes the capital investment needed to: (1) respond to customer requests or city, state, and town requirements; (2) repair failed or damaged equipment; (3) address load growth/migration; (4) maintain reliable service; and (5) sustain asset viability through targeted investments driven primarily by condition. These categories of investment constitute the core of work required for the Company to meet its public-service obligation in Rhode Island.

Q. What other factors did the Company take into account in developing the Electric ISR Plan?

A. In developing the Electric ISR Plan, the Company also performed the following:

- Reviewed the implementation of its new processes for Damage/Failure activities to address the Division's recommendation in Docket 4915;
- Performed a review of the system due to changes in customer load usage as a result of the COVID-19 Pandemic;
- Performed a study of requirements to address increasing Distributed Energy Resources (DER); and
- Revised the Plan materials to create more transparency and clarify the cohesiveness between the Company's planning criteria, Area Planning Studies, System Reliability Procurement, and the Grid Modernization Plan.

To respond to the Division's recommendation on Damage/Failure spending for the FY 2021 Plan, the Company reviews spending in the Damage/Failure category to assess the level of spending that does not relate to failure. To align with the Division's recommendation, the FY 2021 Plan reflects a reduction of $2 million from the Damage/Failure category within the Non-Discretionary portfolio and a transfer of $1 million to each of I&M and Asset Replacement within the Asset Condition category of the Discretionary portfolio. The Company implemented new processes in FY2021 and is assessing how the refined definitions and process are impacting spending in this area and asset replacement. Since the new processes have only been underway for a few months, the Company intends to continue monitoring implementation of this new process in FY 2021 and consider implications on the ISR for the FY 2023 Plan.

The Company has experienced and expects to continue to experience a proliferation of DER. Also, the addition of DER to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. With the interconnection and increase of DER and localized unique demand requirements in certain areas of the system comes a change in loading, voltage, and protection profiles. The issues can have location, time, and direction components such that existing infrastructure and control methods are unable to manage loading, voltage, and protection needs. As DERs continue to develop, more components of the distribution, sub-transmission, and potentially transmission system become impacted, and the distribution system is continuously reconfigured for other reasons (reliability, thermal, voltage, and arc flash performance, etc.) it becomes increasingly difficult to assign certain system infrastructure development costs to any one DER interconnection project. Therefore, the Company put forward a plan to proactively upgrade recloser controls, install new reclosers at circuit connection points, upgrade capacitor controls and regulator controls, and install sensing to sufficiently manage load, voltage, and protection needs. Further detail related to the negotiated plan for those investments is included within Section 2 of the Plan attached as Exhibit 1.

Q. How did the Company respond to potential changes in load usage due to COVID-19?

A. As a result of the COVID 2019 Pandemic and changes in electric load usage, the Company initiated an investigation to analyze peak load scenarios. This scenario analysis was divided into three phases.

- Early in the Pandemic, in the first phase, the Company analyzed feeders servicing medical facilities, testing sites and manufacturing sites to check asset condition, reliability and existing capacity of facilities' services.
- In the second phase, a system-wide feeder review was conducted by adding incremental load to each feeder to simulate possible facility or equipment expansion needs, such as additional ventilators. This review was conducted to investigate system risks for further rapid medical facility deployment and inform the final phase. No

action resulted from this review. It was informative should additional medical load occur.

- The third phase was a system-wide feeder review applying commercial and industrial and residential load shifts that were determined as a reasonable approximation of information gathered from other utilities. The analysis will determine potential issues across the system and identify and implement immediate mitigation actions and solutions. Work under this phase continues, and the Company anticipates continued load shifts and work in future fiscal years. The magnitude of these shifts has yet to be determined.
- Where device overloads, conductor overloads, load imbalance and/or voltage issues are confirmed in the third phase of the scenario analysis through detailed CYME analysis, appropriate solutions are being developed. Solutions include, but are not limited to, fuse replacements, switch replacements, device settings changes, reconductoring, load balancing, and phase extensions

Q. In developing the Electric ISR Plan, did the Company apply the goals and Framework in Docket 4600?

A. Yes. The Electric ISR Plan was developed in a way that advances many of the goals for the electric system that the Commission adopted in Docket 4600. These goals are:

- Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels);

- Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures;
- Address the challenge of climate change and other forms of pollution;
- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;
- Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society;
- Appropriately charge customers for the cost they impose on the grid;
- Appropriately compensate the distribution utility for the services it provides;
- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

Section VI of our joint testimony discusses how the Company applied the Docket 4600 goals and Framework to the Electric ISR Plan.

Q. Please review the FY 2022 capital investment levels.

A. The investment levels proposed for recovery through the Electric ISR Plan for FY 2022 are associated with five key work categories: Non-discretionary work includes (1) Customer Request/Public Requirement; (2) Damage/Failure; and Discretionary work includes (3) Asset Condition; (4) Non-Infrastructure; and (5) System Capacity and Performance. The table below summarizes the proposed spending level for each of these key driver categories proposed.

Proposed FY 2022 Capital Investment by Key Driver Category
($000)

Spending Rationale	Proposed Budget	%
Customer Request/Public Requirement	$31,287	30.2%
Damage Failure	12,198	11.8%
Subtotal Non-Discretionary	43,485	42.0%
Asset Condition	38,401	37.0%
Non-Infrastructure	1,310	1.3%
System Capacity & Performance	18,372	17.7%
Subtotal Discretionary (excl SE Sub)	58,083	56.0%
Asset Condition - Southeast Substation	2,082	2.0%
Subtotal Discretionary (incl SE Sub)	60,165	58.0%
Total FY 2022 Capital Spending	**$103,650**	**100%**

As shown in the table above, a significant portion of the investment for capital projects in FY 2022 are necessary to meet customer requests or city, state, and town requirements. (*i.e*. $31.3 million or 30.2 percent). These investments respond to new customer requests, transformer and meter purchases and installations, outdoor lighting requests and service, and facility relocations related to public works projects requested by the Rhode Island Department of Transportation and also include DER enabling investments and investments to respond to load changes due to COVID-19. Overall, the scope and timing of this work is defined by others external to the Company.

The need to repair failed and damaged equipment totals approximately $12.2 million, or 11.8 percent of the Company's investment. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes.

Together, these items account for approximately $43.5 million or 41.9 percent of proposed capital investment in FY 2022 and are considered mandatory or "non-discretionary" in terms of scope and timing as they are driven by our statutory requirements to provide safe and reliable service. Since the investments associated with these categories of work are non-discretionary, both in terms of timing and scope and are driven by forces outside the Company's control, these categories of spending are subject to necessary and unavoidable deviations.

The asset condition and system capacity projects that the Company will pursue in FY 2022 have been chosen to maintain the overall reliability of the system and collectively total approximately $58.9 million, or 56.8 percent of the Company's proposed FY 2022 capital investment.

Some of the Company's electric infrastructure assets are over 100 years old and are ready for replacement. Projects necessary due to the condition of infrastructure assets account for approximately $40.5 million or 39.1 percent (including the Southeast Substation project), of the proposed capital investment in FY 2022. These projects have been identified to reduce the risk and consequences of unplanned failures of assets based on their present condition. The focus of the assessment is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company plans these investments to minimize potential reliability issues. Examples of such projects in the FY 2022 Plan include long-term projects such as the Southeast Substation, a replacement of the Pawtucket 1 substation, which was constructed in 1907; replacing the Dyer Street Substation, which was constructed in 1925; Admiral Street Substation, which was constructed in 1930.

System capacity and performance projects are required to ensure that the electric network has sufficient capacity to meet the existing and growing, and/or shifting demands of customers. Generally, projects in this category address load conditions on substation transformers and distribution feeders recommended by the Company's system and capacity review and Area Planning Studies. System Capacity and Performance projects account for approximately $18.4 million, or 17.7 percent, of the proposed capital investment in FY 2022. Examples of large projects in this category include: Newport and Jepson substations, which arose from a previous study of the Newport area; New Lafayette Substation, which arose from the South County East Area Study; and East Providence and Warren Substations, which arose from the East Bay Area Study.

Q. Throughout the fiscal year, will the Company provide periodic updates regarding the various categories of capital work approved in the Electric ISR Plan?

A. Yes. The Company will continue to provide quarterly reports to the Division and the Commission on the progress of its Electric ISR Plan programs. Additionally, the Company will provide an annual report on the prior fiscal year's activities when it submits the reconciliation and rate adjustment filings to the Commission. The Company and the Division are aware that in executing the approved Electric ISR Plan, the circumstances encountered during the year may require reasonable deviations from the original Plan. In such cases, the Company will include an explanation of any significant deviations in its quarterly reports and in its annual year-end report.

In addition, the Company will continue to include information on the Narragansett meter purchases and detail on its asset replacement costs in its quarterly reports to provide greater visibility to spending in these areas.

IV. VEGETATION MANAGEMENT PROGRAM

Q. Please describe the FY 2022 spending levels for the Company's Vegetation Management Program that the Company and Division have identified as appropriate to maintain safe and reliable distribution service to customers.

A. The Vegetation Management Program that the Company has reviewed with the Division is carefully balanced to implement the program aspects to a degree and in a manner that will achieve the reliability benefits sought by the Company without unduly burdening customers. For FY 2022, the Company proposes to spend approximately $10.8 million for the Vegetation Management Program. This represents an approximately $200,000 increase from the $10.6 million which was approved for FY 2021. The Company is requesting a continuation of the $200,000 spending first proposed in FY2021 to target pockets of poor performance. These are areas where customers are experiencing a large number of tree-related outages which the Company's routine programs have not been able to address. The Company will track tree-related reliability in these areas to determine the effectiveness of the program and evaluate whether or not the program should continue and or possibly be expanded in the future.

V. INSPECTION AND MAINTENANCE PLAN AND OTHER O&M

Q. Please describe the FY 2022 spending levels for the Company's I&M and Other O&M Program that have been identified by the Company and the Division as appropriate to maintain safe and reliable distribution service to customers.

A. The Electric ISR Plan incorporates the implementation of an inspection program for overhead and underground distribution infrastructure to achieve the objective of maintaining safe and reliable service to customers in the short and long term. The I&M Program is designed to provide the Company with comprehensive system-wide information on the condition of overhead and underground system components. The approximately $0.9 million costs for the I&M Program include O&M repairs associated with the capital program, inspections, voltage testing, completion of 20 percent of the Contact Voltage Program ordered in Docket No. 4237. The other O&M expenses also include $25,000 for the on-going long-range system capacity load study, and $0.3 million for O&M expenses for the Volt/Var expansion program. The Company proposes a total O&M expense budget of approximately $1.2 million for FY 2022.

VI. DOCKET 4600 BENEFIT-COST FRAMEWORK ANALYSIS

Q. Please summarize the purpose of the Commission's Docket No. 4600 Benefit-Cost Framework.

A. In Docket No. 4600, Investigation into the Changing Electric Distribution System, the Commission determined that, due to the changing and modernizing electric distribution system, it was necessary to develop an improved understanding and consistent accounting of the costs and benefits caused by various activities on the system.[3] The Commission sought to answer the following questions:

(1) What are the costs and benefits that can be applied across any and/or all programs, identifying each and whether each is aligned with state policy?

(2) At what level should these costs and benefits be quantified – where physically on the system and where in cost-allocation and rates?

[3] Docket No. 4600, Report and Order at 4-5 (May 4, 2017).

(3) How can we best measure these costs and benefits at these levels – what level of visibility is required on the system and how is that visibility accomplished?[4]

After a thorough stakeholder process, the Commission accepted the Stakeholder Report and adopted the goals, principles and Framework. The Framework includes thirty-four categories of costs and benefits and the Commission also issued a Guidance Document further discussing the goals, principles and values to be considered in connection with the Framework.[5] The Framework identified several methodologies that could be used to quantify costs and benefits, but also recognized that the Framework is meant to be refined or modified over time as the Commission and parties to dockets gain more experience applying the Framework. In adopting the Framework, the Commission held the following:

> The PUC holds that the Framework should be relied upon, but also that it should not be the exclusive measure of whether a specific proposal should be approved. Rather, the Framework should serve as a starting point in making a business case for a proposal. For example, there may be outside factors that need to be considered by the PUC regardless of whether a specific proposal is determined to be cost-effective or not. This may include statutory mandates or qualitative considerations. Such application is consistent with the PUC's broad regulatory authority in setting just and reasonable rates.[6]

[4] *Id*. at 5.
[5] *Id*. at 8.
[6] *Id*. at 23.

Q. Does the Guidance Document provide further detail about how the Framework should be applied in this case?

A. Yes. The Guidance Document provides that a proponent of any proposal affecting the Company's electric rates should provide evidence demonstrating how the proposal advances, detracts from, or is neutral to each of the stated goals of the electric system. Additionally, specific to the Framework, the Guidance Document provides that "any rate design proposal should, at the very least, reference each category within the first two columns of the Report: Mixed Cost-Benefit, Cost, or Benefit Category and System Attribute Benefit/Cost Driver (Categories and Drivers, respectively)."[7] The Guidance Document states that each Categories and Drivers should be discussed and where costs and benefits can be quantified, the proponent should provide the basis for the quantification reached. Where quantification is not possible or practical, the proponent should explain.[8] The Company has followed the directives of the Guidance Document as closely as possible in developing the Docket 4600 assessment for the FY 2022 Electric ISR Plan.

Q. To which programs or capital spending in the Electric ISR Plan did the Company apply the Docket 4600 goals and Framework?

A. In accordance with the Guidance Document[9], the Company applied the Docket 4600 goals

[7] Guidance Document, at 6.
[8] *Id*.
[9] *See Id*. at 6-7.

and Framework to the following new or incremental programs in the Electric ISR Plan: (1) Dyer St. Substation and (2) the three VVO projects (Farnum, Pontiac and Putnam). In addition, the Company applied the goals and Framework to the vegetation management program, as further discussed below.

Q. Are the above listed programs consistent with the goals identified in Docket 4600?

A. Yes. The table below provides a summary comparison of each goal adopted in Docket 4600 to the specific categories of investments listed above. In addition, Exhibit 1, Section 2, Attachment 5 provides a more detailed analysis of the goals and the Framework.

New or Incremental Proposals That Are Expected to Advance Docket 4600 Goals

GOALS FOR "NEW" ELECTRIC SYSTEM	Dyer St Substation	VVO Projects
Provide reliable, safe, clean, and affordable energy	Advances	Advances
Strengthen the Rhode Island economy	Advances	Advances
Address climate change and other forms of pollution	Neutral	Advances
Prioritize and facilitate increasing customer investment in their facilities	Neutral	Neutral
Appropriately compensate distributed energy resources	Neutral	Neutral
Appropriately charge customers for the cost they impose on the grid	Neutral	Neutral
Appropriately compensate the distribution utility for the services it provides	Advances	Advances
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives	Neutral	Advances

As shown in the table, above, these categories of investments advance several of the goals identified in Docket 4600. Attachment 5 to Section 1 of the Plan provides additional details on how each of the listed investments advances, detracts from, or is neutral to each goal.

Q. Did the Company apply a quantitative and qualitative analysis of the above listed programs?

A. Yes. The Company prepared a matrix using both the "Mixed Cost-Benefit, Cost, or Benefit Category" information in the Framework. The Company used this matrix to determine a quantitative result, where one could be identified, and also included a qualitative assessment of the investment for each category, where one existed. The Company's analysis is presented in Section 2, Attachment 5 of the Plan, attached hereto as <u>Exhibit 1</u>.

Q. For those categories that were quantified, what method did the Company use to quantify the costs and benefits?

A. All cost and benefit calculations are based on a 20-year period net present value, with the cost calculations taking into consideration revenue requirements. Transmission costs are currently calculated on a regional basis. The analysis will be refined to prorate the cost on a Rhode Island basis. To calculate reliability benefits, the Company used the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs. The Company based all energy saving calculations on externally developed Peak/Off peak prices and Renewable Energy Certificate (REC) values and escalations factors. The Company based CO_2 reduction calculations on Regional Greenhouse Gas Initiative (RGGI) values. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

This is the same methodology that the Company applied to the FY 2021 Electric ISR Plan; however, it is important to note that the Company has not adopted this methodology for all utility investments, nor has it been fully vetted with the Commission or stakeholders, outside of the FY 2021 Electric ISR Plan. The Company has applied this methodology again to the FY 2022 Electric ISR Plan to illustrate a possible quantitative assessment under Docket 4600. Notwithstanding this assessment, the Company maintains that for traditional utility infrastructure projects, especially significant asset condition driven projects, a quantitative assessment may not be appropriate and it is more important to focus on the qualitative assessment. We address this in more detail in connection with the specific investments below.

Dyer Street. Substation

Q. Please describe how the Company applied the Framework to the review of the Dyer Street Substation.

A. As is the case with traditional infrastructure investments, the Company considered multiple alternatives to address asset condition and loading issues identified in the Providence area study. In this case, two alternatives were assessed. The first alternative is the recommended plan, which is to build a new 11.5/4.16kV substation within the South St substation outdoor yard consisting of two 11.5kV-4.16kV transformers and one 4.16kV metalclad switchgear with 8 feeder positions. This plan also includes rehabilitation of the historically significant DC / warehouse building at the existing Dyer Street substation site as required by the City of Providence, removal of all retired 4 kV and 11 kV equipment and cable from the existing Dyer Street indoor substation and yard, and demolition of the Dyer Street Indoor Substation building. The second alternative is to restore the currently vacant DC / warehouse building on the southwest corner of the existing National Grid Dyer Street site and build a new 11.5-4.16 kV indoor distribution substation within the restored DC building. This alternative also includes retiring the existing Dyer Street Indoor Substation at the southeast corner of the site.

In applying the Framework to each alternative, the Company assessed the costs and benefits at the Power System Level, Customer Level, and Societal Level categories, consistent with Docket 4600. To the extent costs or benefits within each category could be quantified, the Company included that in its analysis. Where costs and benefits could not be quantified, the Company included a qualitative assessment. It is important to note that most of the benefits within each category were not applicable to asset condition driven projects or programs, and the Company noted that in its analysis. The Company's analysis for both alternatives is presented in Section 2, Attachment 5 of the Plan.

Q. What are the results of the Company's Docket 4600 costs and benefit analysis?

A. The Dyer Street substation preferred plan yields net benefits of -$25,175,150.43, whereas the alternative plan yields net benefits of -$50,217,725.00. However, both the recommended plan and the alternative plan have a benefit-cost ratio of near 0.00. *See* Section 2, Attachment 5 of the Plan.

Q. Are there outside factors not captured in the Docket 4600 analysis that should be considered?

A. Yes. As stated in the Docket 4600 Guidance Document "…there may be outside factors that need to be considered by the Commission…"[10] In this case, the results of applying the framework to the Dyer Street project show that the Docket 4600 Framework does not capture all benefits of traditional utility infrastructure projects, especially for asset condition driven projects. For example, when assessing the distribution system

[10] Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid, http://www.ripuc.ri.gov/eventsactions/docket/4600A-GuidanceDocument-Final-Clean.pdf, page 7.

performance benefit at the Power System Level, it was not possible to quantify the impact of not addressing the asset condition or clearance issues. Taking no action would leave all the asset condition issues unaddressed, which would only worsen over time, thereby increasing the risk of adversely affecting customer service and reliability performance. The Framework does not seem to adequately account for system risk involved in not performing the Dyer Street substation work.

Q. For asset condition projects, what does the Company suggest in terms of utilizing the Docket 4600 analysis?

A. The results of the Docket 4600 analysis have shown that for asset condition projects, most Docket 4600 categories have modest or no results, and the least cost option will always be recommended. The Company already has risk methods to determine asset condition needs and is not recommending that the Docket 4600 Framework be revised. Instead, the Company proposes that the Docket 4600 Framework should only be applied to certain types of projects that fit the framework, such as DER Enabling projects. For asset condition, driven projects, the Company proposes to utilize its traditional least cost planning analysis to future asset condition projects.

VVO Projects

Q. Please describe how the Company applied the Framework to the review of the VVO Projects.

A. The intent of the Volt/VAR Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion projects is to flatten and lower feeder voltage profiles using additional voltage monitors along the feeder and centralize control of the regulating devices based on real time system performance. The lowering of feeder voltages benefits customers by reducing the demand and energy usage. In the FY22 Electric ISR Plan, the Company proposes installing VVO/CVR at three substations: Farnum Pike, Pontiac and Putnam Pike.

In applying the Framework, The Company assessed the costs and benefits at the Power System Level, Customer Level, and Societal Level categories, consistent with Docket 4600. To the extent costs or benefits within each category could be quantified, the Company included that in its analysis. The Company's analysis for the VVO projects is presented in Section 2, Attachment 5 of the Plan.

Q. What are the results of the Company's Docket 4600 costs and benefit analysis?

A. The VVO project at Farnum Pike yields net benefits of $3,793,864.75 with a benefit-cost ratio of 2.67. The VVO project at Pontiac substation yields net benefits of $4,003,310.27 with a benefit-cost-ratio of 3.22. The VVO project at Putnam Pike yields net benefits of

$2,427,088.18 with a benefit-cost-ratio of 1.61. See Section 2, Attachment 5 of the Plan. In addition to the quantitative assessment, the Company also applied a qualitative assessment.

Vegetation Management

Q. Did the Company perform a similar analysis for the incremental spending in the vegetation management program?

A. Yes; however, it is important to note that the Company's vegetation management program precedes Docket 4600 and the Framework. The Company initially developed its vegetation management program by using industry standards and utility best practices. Nonetheless, the vegetation management program aligns today with several Docket 4600 goals. In addition to the quantitative benefits as presented in the Company's benefits-cost analysis (BCA), which is included in Section 3, Attachment 1 of the Plan, Section 2, Attachment 5 of the Plan provides additional details on how the vegetation management program advances, detracts from, or is neutral to each goal. As demonstrated in the BCA, the Company's program results in sustained reliability improvements on circuits for several years after completion. This directly impacts the power sector benefits category in the Framework for distribution system and customer reliability/resilience impacts.

Q. Did the Company quantify a value for the effect of the benefits and costs for the vegetation management program?

A. Yes. Since 2012, in preparation for discussion and negotiations of the annual Electric ISR Plan, the Company has provided the Division with a vegetation management BCA, which details and demonstrates the benefits and value of the Enhanced Hazard Tree Mitigation, Damage Restoration, and Cycle Pruning programs included in the vegetation management program, as well as the reliability benefits of these programs. The Company submitted this BCA to the Division on August 10, 2020 as part of its pre-planning documents in preparation for developing the Electric ISR Plan. The Company has included this BCA in Section 3, Attachment 1 of the Plan.

Q. Please describe the methodology that the Company used for the BCA for the vegetation management program?

A. The Company quantifies the reliability benefits for both the Enhanced Hazard Tree Mitigation and the Cycle Pruning Programs on a fiscal year basis with the benefits determined by comparing a pre-project three-year average to a post-project tree-related number of customers interrupted and the costs calculated by a cost per feeder to calculate an overall cost-per-change in customer interruptions. The Company calculates the damage restoration cost benefit analysis for the Enhanced Hazard Tree Mitigation

Program circuits using a similar method and estimates the costs of restoration for each outage.

Q. Is there a statutory standard that supports an additional value case for the Plan?

A. Yes. R.I. Gen. Laws § 39-1-27.7.1 identifies specific categories of costs to be included in the ISR Plan: (1) capital spending on utility infrastructure; (2) operation and maintenance expenses on vegetation management; (3) operation and maintenance expenses on system inspection, including expenses from expected resulting repairs; and (4) any other costs relating to maintaining safety and reliability that are mutually agreed upon by the Division of Public Utilities and Carriers (Division) and the Company. In addition, the statute requires that the Company consult with the Division regarding the ISR Plan, and the Division to cooperate in good faith to reach an agreement on the proposed plan within sixty (60) days. If the Company and the Division mutually agree on a plan, the Company will file such plan with the Commission for review and approval within ninety (90) days. If the Company and the Division cannot agree on a plan, the Company shall file a proposed plan with the Commission for review, and if the investments and spending are found to be reasonably needed to maintain safe and reliable distribution service over the short and long term, the Commission will approve the plan within ninety (90) days. The Electric ISR Plan is consistent with Rhode Island law, and the proposed investments are reasonably necessary to maintain safe and reliable distribution service over the short and long term. System reliability and resiliency, and safety are specific power system level benefit categories that the Framework recognizes. These are not easily quantified, as discussed above. As Division Witness Booth testified in the FY 2019 Electric ISR Plan in Docket No. 4783, there is no specific metric to measure how much safety or reliability improves relative to spending in the Plan; however, absent an I&M program, a vegetation management program, and increases in the capacity of the distribution system, reliability will deteriorate below acceptable levels.[11] The ISR process, particularly the planning process and consultation between the Company and the Division, as prescribed by statute, is a robust process and ensures a level of scrutiny as further justification for Plan spending.[12]

VII. <u>CONCLUSION</u>

Q. In your opinion does the Electric ISR Plan fulfill the requirements established in relation to the safety and reliability of the Company's electric distribution system in Rhode Island?

A. Yes. The Electric ISR Plan is designed to establish the capital investment, vegetation management, and I&M activities in Rhode Island that are necessary to meet the needs of Rhode Island customers and maintain the overall safety and reliability of the Company's electric distribution system. The Company believes that the proposed Plan accomplishes these objectives. As such, the Commission's approval of the proposed Electric ISR Plan

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[11] *See* Docket No. 4783, Tr. at 161-165.
[12] *Id*. at 165.

is essential for the Company to continue maintaining a safe and reliable electric distribution system for its Rhode Island customers.

Q. Does this conclude this testimony?

A. Yes, it does.

Exhibit 1
Electric ISR FY2022

The Narragansett Electric Company
d/b/a National Grid

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

December 21, 2020

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Table of Contents

Section 1
Introduction

Section 1

Executive Summary
FY 2022 Electric ISR Plan

Section 1: Executive Summary

National Grid[1] has developed the proposed Fiscal Year 2022 (FY 2022) Electric Infrastructure, Safety, and Reliability Plan (the Electric ISR Plan or Plan) in compliance with Rhode Island's Revenue Decoupling statute, which provides for an annual electric "infrastructure, safety, and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget."[2] Through the Plan, the Company proposes both capital and operation and maintenance (O&M) spending to provide safe and reliable electric service. The Plan is the product of a collaborative effort with the Rhode Island Division of Public Utilities and Carriers (Division), which included several meetings and discussions on the Plan since August.

The FY 2022 Electric ISR Plan includes an overview of the system planning process that leads to the Company's long-range plan; the development of the Annual Work Plan and the estimating process; the proposed FY 2022 Capital and O&M spending plan; a description and calculation of the revenue requirement; a description of the proposed rates; and customer bill impacts. The Company will continue to file quarterly reports with the Division and the Rhode Island Public Utilities Commission (Commission) concerning the progress of its Electric ISR Plan programs. In addition, the Company will file the annual report on the prior fiscal year's activities when it submits its reconciliation and rate adjustment filing. In implementing the Plan,

1 The Narragansett Electric Company d/b/a National Grid (National Grid or Company).
2 R.I. Gen. Laws § 39-1-27.7.1, An Act Relating to Public Utilities and Carriers – Revenue Decoupling.

the circumstances encountered during the year may require reasonable deviations from the original Plan. In such cases, the Company will include in its quarterly and annual reports an explanation of any significant deviations.

Through the Plan, the Company will maintain and upgrade its electric distribution system by proactively replacing aging equipment, upgrading equipment to address load growth or migration, respond to emergency and storm events, and address infrastructure requirements that arise out of state, municipal, and third-party construction projects. FY 2022 Electric ISR Plan proposes spending of $103.7 million of capital investment, $10.8 million of Vegetation Management O&M spending, and $1.2 million of Other O&M spending. This level of capital investment is $0.1 million lower than the Company's approved FY 2021 Electric ISR Plan of $103.8 million. The total O&M spending of $12.0 million is $0.1 million lower than FY 2021's approved O&M spending of $12.1 million. The Company is submitting this Plan to the Commission for final review and approval.[3]

[3] R.I. Gen. Laws § 39-1-27.7.1 (d) provides that the Company and the Division must work together over the course of 60 days in an attempt to reach an agreement on a proposed plan, which the Company must then file with the Commission for its review and approval.

Section 2

Electric Capital Plan
FY 2022 Electric ISR Plan

Section 2: Electric Capital Plan

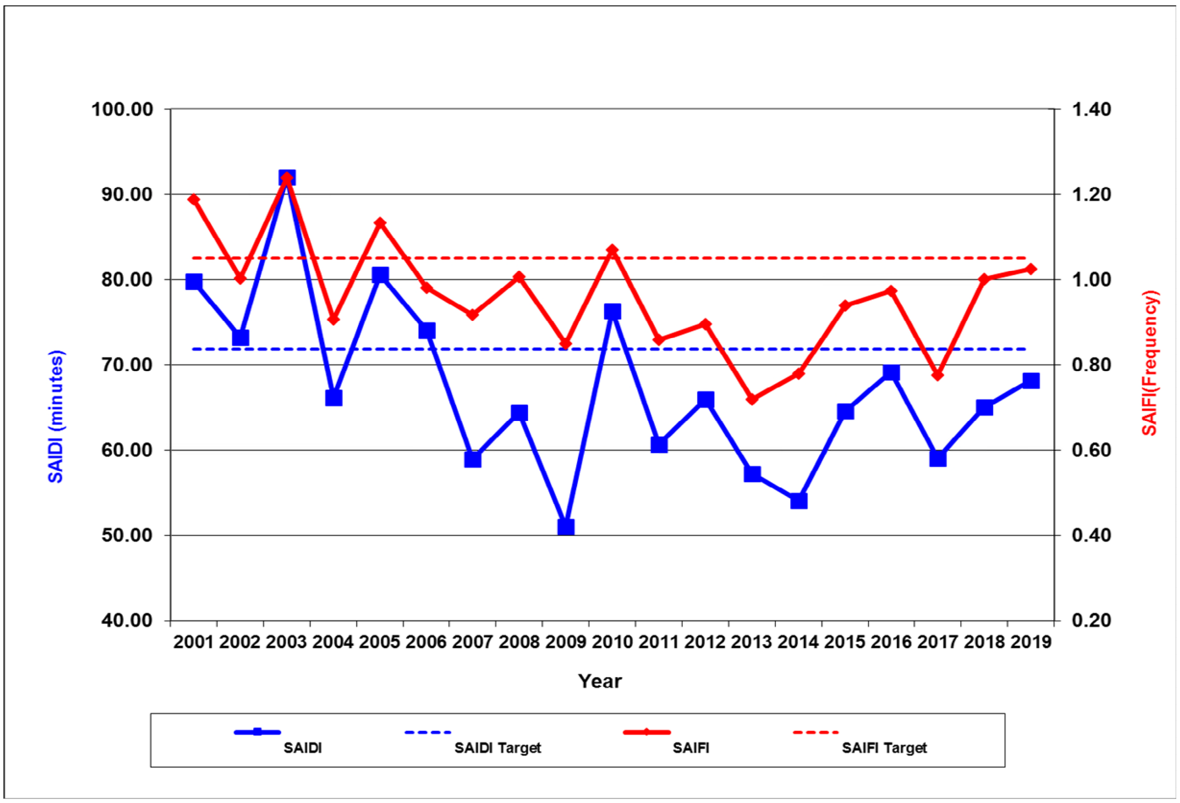
The Company developed the FY 2022 Electric ISR Plan to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs. As of March 2020, the Company delivers electricity to 498,294 Rhode Island customers in a service area that encompasses approximately 1,076 square miles in 38 Rhode Island cities and towns. To provide this service, the Company owns and maintains 5,133 miles of overhead and 1,121 miles of underground distribution and sub-transmission circuit that includes 421 distribution feeders and 59 sub-transmission lines. The Company relies on 64 distribution substations that house 116 power transformers and 849 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 282,930 distribution poles, 4,616 manholes, and 66,869 overhead (pole mounted) and underground (pad-mounted or in vault) transformers.

The Plan includes spending needed to (1) respond to customer requests and city, state, and town requirements; (2) repair failed and damaged equipment; (3) address load growth and migration; (4) maintain reliable service; (5) sustain asset viability through targeted investments driven primarily by asset condition; and (6) enable Distributed Energy Resource (DER) integration.

Since the inception of the ISR in FY 2012, the Company has consistently met its system reliability goals. As shown below in Chart 1 below, the Company met both its calendar year (CY) System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2019, with SAIFI of 1.02 against a target of 1.05, and SAIDI of 68.2 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days [4]. See Attachment 3 for further detail related to system performance reliability data.

Chart 1

RI Reliability Performance
CY 2001 – CY 2019
Regulatory Criteria (Excluding Major Event Days)



4 A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (5.05 minutes for CY 2019). 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.

System Planning

Proposed projects to meet system safety and reliability are developed through a pro-active annual capital work plan process. The Company relies on comprehensive planning guidelines combined with detailed system reviews to determine annual investment requirements. The planning process for the FY 2022 ISR Plan takes place over many months and is a dynamic and iterative process that involves multiple cross-functional teams. The work plan is continually updated for future years based on issues identified on the system, changing circumstances and outcomes of area studies.

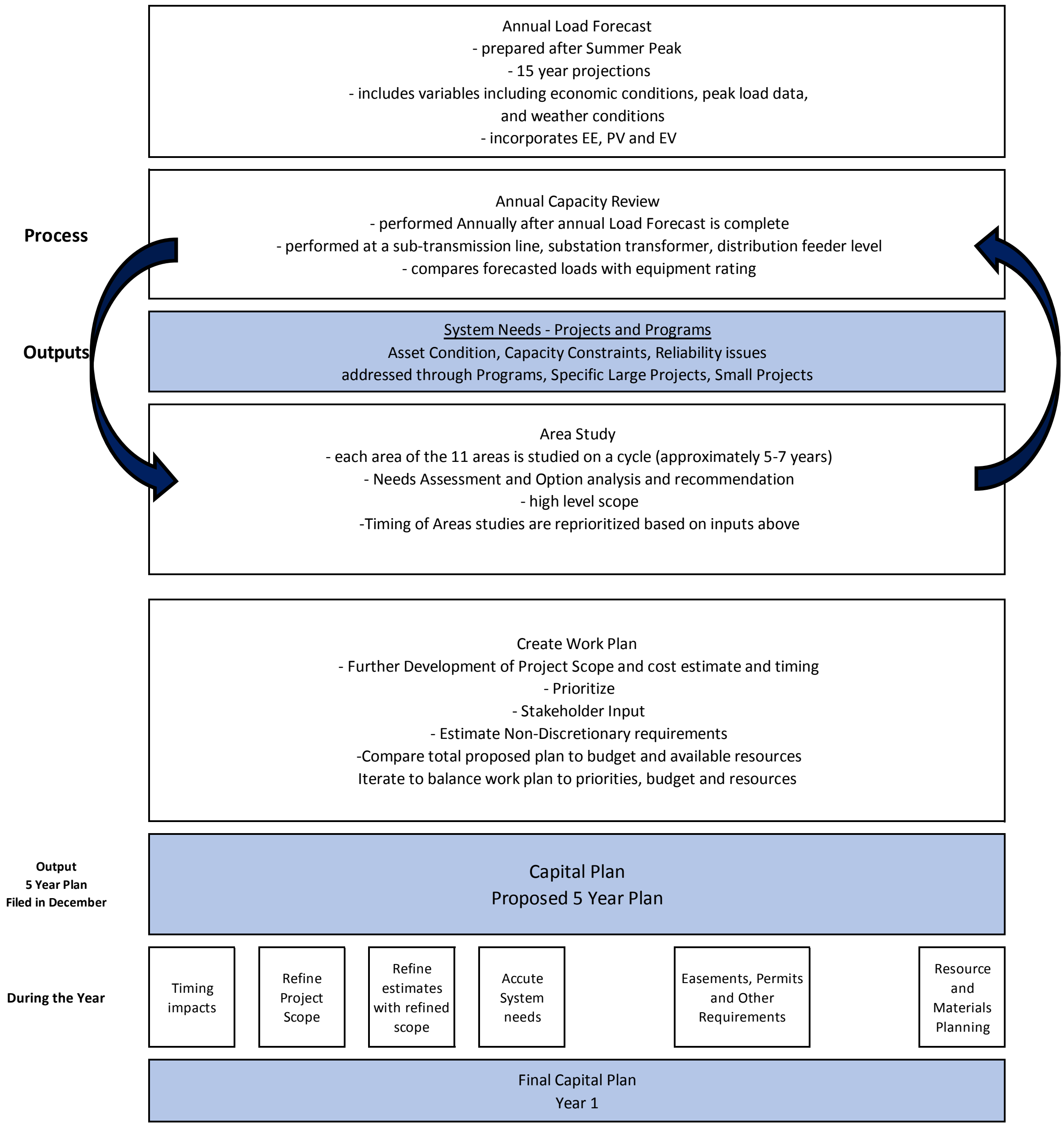
Before developing the annual ISR Plan, the Company conducts an annual load forecast and routine system analyses on its distribution system in the form of capacity reviews, area studies, also known as area planning studies, and other integrated planning analyses.

Capacity reviews are completed annually using the most recent load forecast for each of the study areas in the Company's service territory. A capacity review is conducted to identify thermal capacity constraints and assess the capability of the network to respond to contingencies that might occur. In preparing for the FY 2022 Electric ISR Plan, the Company has completed 100% of the capacity reviews in the eleven study areas.

The capacity reviews inform the execution of the Company's long-range system capacity studies which are performed through a series of area planning studies. Area planning studies are comprehensive technical reviews of areas within the Company's service territory to determine system needs and solutions over a 10-15 year timeframe. The study outcomes result in infrastructure development recommendations that are ultimately proposed in the ISR Plan or Non-Wires Alternative Plans progressed in the SRP.

Below, Chart 2 depicts the Company's processes from planning to completion for electric capital work. Additional detail is provided in the following sections.

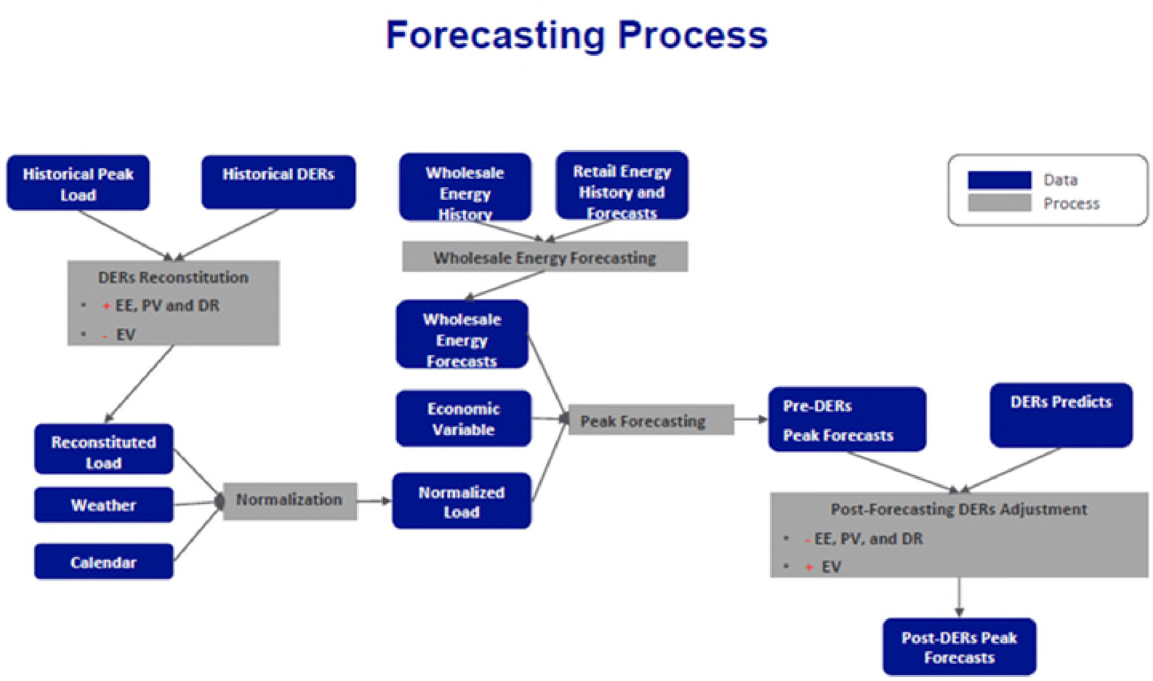
Chart 2
Capital Work Plan Process



Load Forecasting

The Company's Electric Forecasting team uses a regression-based core model to forecast summer and winter peak loads. Forecasts are developed annually and have 15-year projections. The explanatory variables in this model include historical and forecasted economic conditions specific to Rhode Island, historical peak load data, annual energy sales, and weather conditions based on historical data from the Providence weather station. The chart below shows the data and process flows associated with forecasting load.

Chart 3
Load Forecasting Process



This model is used to predict the forecasted peak demand for the State under a normal and extreme weather scenario. The normal weather scenario assumes the same normal peak-producing weather for each year of the forecast. The extreme weather scenario assumes an upper bound peak demand under extreme weather conditions. This scenario infers that there is a five percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario.

The forecast of peak load incorporates distributed energy resources, or DER's, such as energy efficiency (EE) savings, solar-photovoltaics (PV) reductions and electric vehicle (EV) increases achieved through 2019 since these impacts would be reflected in the historical data used by the model. The Company subtracts forecasted EE savings and PV reductions and adds the forecasted EV impacts beyond the amounts achieved through 2019 from the load forecast. A base case is developed using current trends, approved programs, and existing state policy targets. They are considered the most probable scenario at this time. Scenarios of varying levels and types of DER adoption are developed to provide additional insights into what loads could look like under different scenarios. System Planning uses the base case load with DER projections from the most recent load forecast for System Capacity and Area Planning Reviews.

Annual Capacity Review

Peak load values from the annual electric forecast report described above are the basis for the capacity reviews performed by Distribution Planning & Asset Management. Capacity reviews are completed annually. They identify imminent thermal capacity constraints and assess the capability of the network to respond to contingencies. The capacity planning process includes the following tasks:

- Review historic loading on each sub-transmission line, substation transformer, and distribution feeder;
- Apply and evaluate impacts of the weather adjustment on recent actual peak loads as per the Electric Peak (MW) Forecast;
- Apply and evaluate impacts of the econometric forecast of future peak demand growth as per the Electric Peak (MW) Forecast;
- Analysis of forecasted peak loads with comparison to equipment ratings;
- Consideration of system operational flexibility to respond to various contingency scenarios.

Growth rates are applied to each feeder and sub-transmission line in each area. Specific feeder, sub-transmission line and/or transformer forecasts are adjusted to account for known spot load additions or subtractions, as well as planned load transfers due to system reconfigurations. Feeder/substation forecasted peak loads under the extreme weather scenario are used to perform planning studies and to determine if the thermal capacity of facilities is adequate for future load level projections.

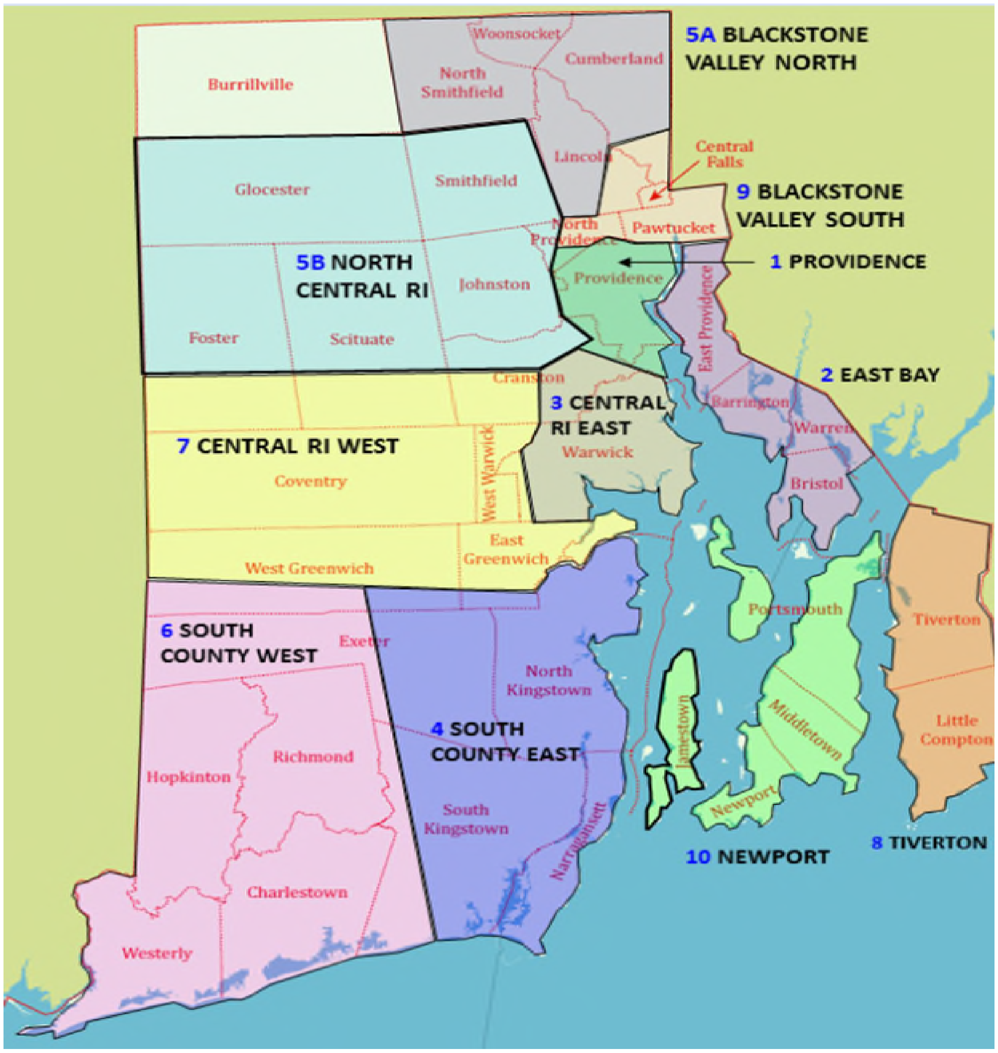
Individual project proposals are identified to address imminent planning criteria violations. At a conceptual level, the Company prioritizes these small-scale project proposals and submits them for inclusion in future year capital work plans. This is the type of work that could generally arise during the Plan year. In addition, during each year's capacity review, the implementation schedule of large projects recommended through Area Planning Studies is assessed and adjusted if conditions indicate an adjustment is needed. This process validates and confirms the need date and implementation schedule of capacity related projects before inclusion in the ISR Plan.

Area Planning Studies

In addition to identifying imminent issues and corresponding small-scale solutions, annual Capacity Reviews assist in prioritization of Area Planning Studies. Areas with more normal and contingency overloads might be prioritized over areas with fewer issues identified in the Annual Capacity Reviews. Area Planning Studies are more comprehensive reviews of the areas within the Company's service territory that result in long-term infrastructure development recommendations with defined project scopes to solve system issues identified over a 10 to 15 year period. The chart below shows the Company's regional boundaries and study areas and for each area the high-level evaluations and resolutions resulting from capacity reviews or completed area planning studies.

The Company has developed guidelines for the consideration of non-wires alternatives (NWA's) in the distribution planning process that are incorporated into Area Planning Studies. The goal of these guidelines is to develop a combination of wires and non-wires alternatives that solve capacity deficiencies in a cost-effective manner, factoring in the potential benefits and risks. See separate discussion of NWA's later in the plan material.

Chart 4
Area Planning Summary



1 PROVIDENCE
Concerns: Asset condition, capacity to supply load growth in an urban environment.
Resolutions: Long Term Study completed in May 2017.

2 EAST BAY
Concerns: Normal and contingency capacity issues, asset condition concerns.
Resolutions: Study completed August 2015.

3 CENTRAL RI EAST
Concerns: Normal and contingency capacity issues, long term capacity plan needed to supply eastern Warwick, flood risk at Sockanosett (pending solution in Providence study), contingency issues at Kilvert St. (solution in progress).
Resolutions: On-going Kilvert St substation project will address contingency issues. Study completed February 2017.

4 SOUTH COUNTY EAST
Concerns: Potential feeder MWh violations, potential MWh violations at Tower Hill.
Resolutions: Solutions outlined in 2018 study will address issues in area.

5A BLACKSTONE VALLEY NORTH (Northwest RI)
Concerns: Contingency MWHR violation on the Nasonville issues, Asset Condition concerns at Centerdale and Greenville, Municipal Electric Stakeholder.
Resolutions: On-going study to resolve issues.

5B NORTH CENTRAL RI (Northwest RI)
Concerns: Normal and contingency capacity issues, Asset condition concerns.
Resolutions: Conducted in concert with Blackstone Valley North Study. On-going study to resolve issues.

6 SOUTH COUNTY WEST
Concerns: Contingency capacity issues, Flooding concerns at Westerly Substation, Westerly Substation islanded in terms of phasing from surrounding area, Voltage concerns & reliability issues on feeders supplying Hopkinton and Richmond area.
Resolutions: Recently completed Chase Hill Substation has assisted in addressing capacity issues. On-going area study to outline and identify solutions to resolve remaining issues.

7 CENTRAL RI WEST
Concerns: Contingency capacity issues Divisions Street, asset condition concerns at Arctic, contingency issues at Kent County, asset, flood risk, & environmental concerns at Hunt River, asset condition issues at several other sub transmission supplied stations, such as Anthony and Coventry.
Resolutions: Completed New London Ave substation project has addressed asset condition concerns at Arctic, completed Kent County substation project has addressed contingency issues and Hunt River issues, on-going area study to outline and identify solutions to resolve remaining issues.

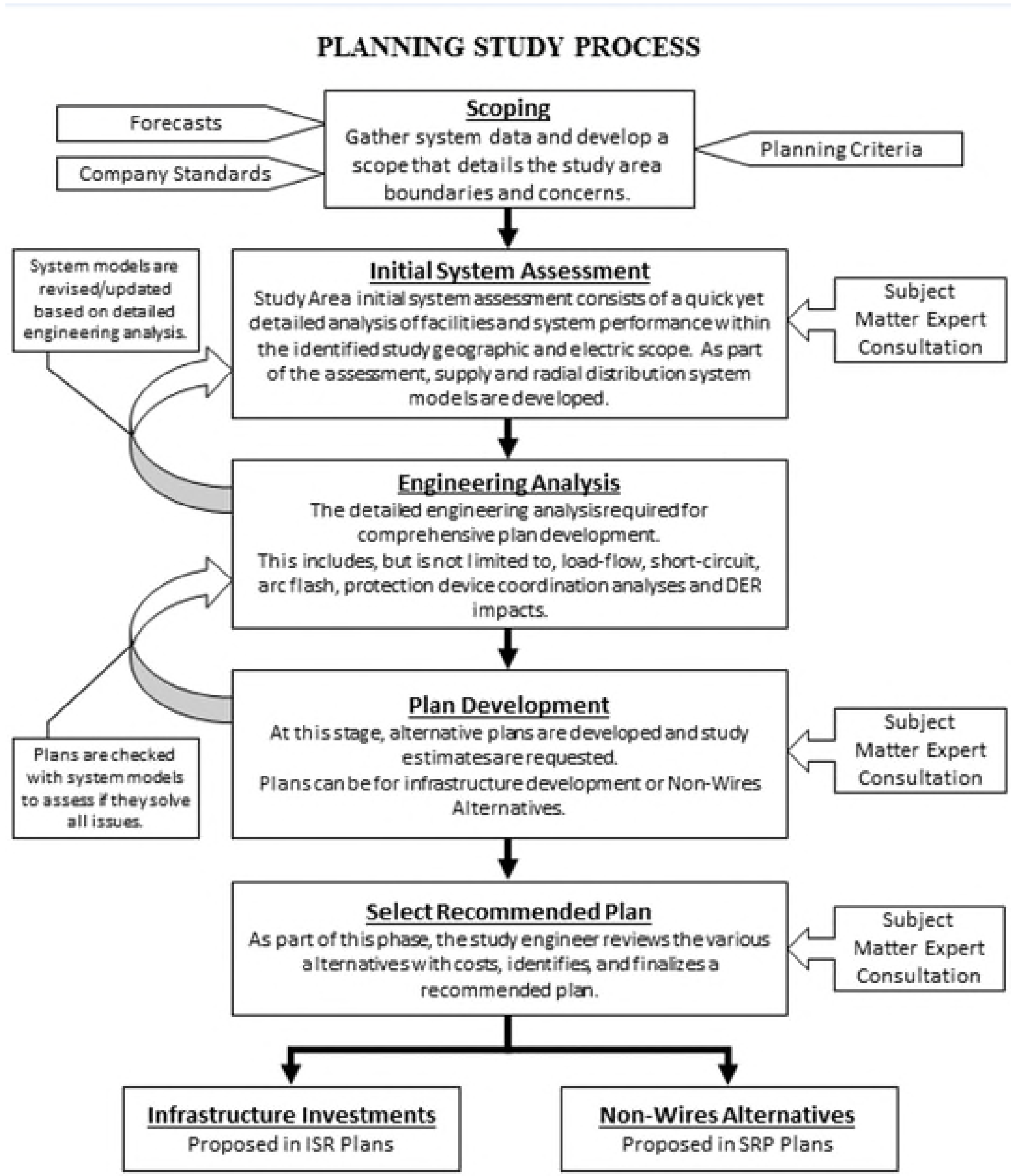
8 TIVERTON
Concerns: Feeders exceeding 90% of thermal rating, contingency capacity issues on transformer and feeder level, reliability issues due to bare open wire construction in heavily treed areas of Little Compton.
Resolutions: On-going area study to outline and identify solutions to resolve remaining issues.

9 BLACKSTONE VALLEY SOUTH
Concerns: Asset condition concerns at Pawtucket No 1 Indoor substation, asset condition concerns at Pawtucket No 2 Indoor substation, normal and contingency capacity issues at Pawtucket No 1.
Resolutions: On-going Southeast substation project will address all asset and capacity issues at Pawtucket No 1, additional concerns to be reviewed during the study include asset condition and capacity issues at Pawtucket No. 2 indoor substation.

10 NEWPORT
Concerns: Normal and contingency capacity issues, asset condition concerns at Vernon & Bailey Brook, sub-transmission capacity concerns
Resolutions: On-going area reconfiguration and new substations (Newport and rebuilt Jepson) should address most issues in area, Remaining concerns will be reviewed in a to be kicked off area study after existing conversion and rebuild is complete.

Area Planning Studies enhance the ability to meet obligations to provide safe, reliable and efficient electric service for customers at reasonable costs. The studies typically address issues in a 10- to 15-year window and typically start 5 to 7 years after the last study was completed. Commencement and completion dates are subject to change based on various system assessments that inform the prioritization of future studies.

Chart 5
Area Planning Study Process



Area Planning Studies include the following stages:

- **Stage 1:** Definition of electrical and geographical scope of study and gathering necessary data needed to execute the study;
- **Stage 2:** Initial system assessment consisting of a quick analysis of facilities and system performance within the identified study geographic and electric scope;
- **Stage 3:** Study kick off meeting held to inform the larger stakeholder group that an area planning study is underway and to solicit inputs from those with knowledge of the system infrastructure in the area under review;
- **Stage 4:** Detailed system assessment and engineering analysis;
- **Stage 5:** Development and project estimating of alternative infrastructure and non-wires alternative plans;
- **Stage 6:** Review of various alternatives' relative costs and benefits, and identify and finalize a recommended plan;
- **Stage 7:** Technical review presentation with approval committee;
- **Stage 8:** Delivery of area planning study report documentation upon completion of the study;
- **Stage 9:** Sanction of any recommended projects having forecasted spending within the next three fiscal years.

See Chart 6 below for the Status of Area Planning

Chart 6
National Grid's Study Areas: Current Priority and Statistics

Rank	Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Annual Planning Review % Status	Area Planning Study % Complete	Area Planning Study Stage	Estimated Planning Study Complete Date	Expected Commencement of next Area Study
1	Providence	358	19%	95	17	100%	100%	Stage 9	Complete 2017	2024
2	East Bay	147	8%	22	7	100%	100%	Stage 9	Complete 2015	2022
3	Central Rhode Island East	204	11%	37	9	100%	100%	Stage 9	Complete 2017	2024
4	South County East	159	9%	22	9	100%	100%	Stage 9	Complete 2018	2025
5A	Blackstone Valley North	139	8%	27	6	100%	85%	Stage 7	Mar-2021	2028
5B	North Central Rhode Island	269	15%	35	10	100%	85%	Stage 7	Mar-2021	2028
6	South County West	98	5%	14	5	100%	40%	Stage 4	Dec-2021	2028
7	Central Rhode Island West	167	9%	33	11	100%	60%	Stage 5	Sep-2021	2028
8	Tiverton	28	2%	4	1	100%	20%	Stage 3	Aug-2021	2028
9	Blackstone Valley South	171	9%	54	11	100%	20%	Stage 3	Oct-2021	2028
10	Newport	105	6%	42	12	100%	5%	Stage 1	Dec-2021	2028
	TOTALS*	**1845**	**100%**	**385**	**98**	**100%**	**76%**			

* Study Status Total = % State Load weighted total

Non-Wires Alternatives

During Stage 5 of an Area Planning Study, projects are screened for non-wires alternatives (NWA). If a project passes the NWA screening, development of the wires and NWA solutions is done in parallel, prior to advancing either solution through the ISR or System Reliability Procurement (SRP) plans. Once all alternatives have been evaluated and viable bids are received for any NWA option, the least cost, fit-for-purpose option will be selected. If the NWA option is selected as the recommended plan, it will advance through SRP and no wires alternative will be included in the ISR. If the wires solution is selected as the recommended plan, it will advance through the ISR, with no NWA included in the SRP. Only one alternative will be selected and progressed, either through the SRP or the ISR. In accordance with the Least Cost

Procurement (LCP) Standards,[5] the Rhode Island NWA screening criteria has been proposed through the Three-Year SRP Plan. The 2021-2023 SRP Three-Year Plan was filed with the Commission on November 20, 2020 in Docket No. 5080.[6]

NWAs, like other SRP investment proposals, are progressed for regulatory review in accordance with the LCP Standards. The LCP Standards provide that the Commission prefers that SRP investment proposals be filed alongside, but separately from, annual ISR Plans. Please refer to Section 1 of the 2021-2023 Three-Year SRP Plan document for a summary of the proposals and commitments in the SRP program.

Chart 7 below shows the current projects in the FY2022 ISR that originated from an area planning study or a study from previous legacy planning processes. The Company has agreed with the Division's recommendation that all new projects are advanced into the ISR after an Area Planning Study is completed by the Company and reviewed by the Division.

More detailed descriptions of these projects are included in the Summary of Investment Plan by Key Driver section of the Plan.

[5] The LCP Standards were approved and adopted pursuant to Order No. 23890 in Docket No. 5015 and may be found at http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf.

[6] Please see Section 7.2 of the 2021-2023 SRP Three-Year Plan. http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf

Chart 7
Large Projects and Associated Area Planning Study

Project	Respective Planning Area Study
Southeast (aka Dunnell Park)	Legacy Project - Blackstone Valley North
Dyer Street - Indoor Substation	Legacy Project - Respected in Providence System Area Study
Providence LT Study	Providence
Aquidneck Island (Newport projects)	Legacy Project - Newport
New Lafayette Substation	South County East
Warren Substation	East Bay
East Providence Substation	East Bay

Additional Planning Analyses

Annual Capacity reviews are the basis for load flow planning models that are used for many different types of planning analysis. Additional Planning activities performed by Distribution Planning & Asset Management include, but are not limited to,

- Distributed Generation (DG) System Impact Studies (SIS)
- Large new customer load request reviews
- Acute reliability and/or voltage issue reviews
- Operations and Control Center support
- Arc flash/fault duty customer requests

COVID-19 Impacts and Analysis

As a result of the COVID 2019 Pandemic and changes in electric load usage, the Company initiated an investigation to analyze peak load scenarios. This scenario analysis was divided into three phases.

- Early in the Pandemic, in the first phase, the Company analyzed feeders servicing medical facilities, testing sites, and manufacturing sites to check asset condition, reliability, and existing capacity of facilities' services.
- In the second phase, a system-wide feeder review was conducted by adding incremental load to each feeder to simulate possible facility or equipment expansion needs, such as additional ventilators. This review was conducted to investigate system risks for further rapid medical facility deployment and inform the final phase. No action resulted from this review. It was informative should additional medical load occur.
- The third phase was a system-wide feeder review applying commercial and industrial and residential load shifts that were determined as a reasonable approximation of information gathered from other utilities. The analysis will determine potential issues across the system and identify and implement immediate mitigation actions and solutions. Work under this phase continues, and the Company anticipates continued load shifts and work in future fiscal years. The magnitude of these shifts has yet to be determined.

- Where device overloads, conductor overloads, load imbalance, and/or voltage issues are confirmed in the third phase of the scenario analysis through detailed CYME analysis, appropriate solutions are being developed. Solutions include, but are not limited to, fuse replacements, switch replacements, device settings changes, reconductoring, load balancing, and phase extensions.

The Company proposes to invest $2 million in the Non-Discretionary category in FY 2022 and will review the analysis and recommendations of large COVID projects with the Division before performing work in this category.

Strategic DER Advancement and Grid Modernization

In Rhode Island, there are a number of policies, programs, and technologies that impact customers. These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to traditional, centralized power supplies. DER is a resource sited close to customers that can provide electricity generation (*e.g.*, solar or wind) or flexible demand *(e.g.*, energy storage, EVs, electric heat pumps). With the proliferation of DER interconnections, the Company is experiencing rising complexity related to managing load, voltage, and protection systems that are the key to system reliability and safety. The related requirements may involve new programmatic investments, major system modifications, or potential DER project reductions to accommodate projects without creating system compliance issues. To more readily be able to respond to DER interconnections, several targeted investments were proposed within the FY 2021 ISR plan that would contribute to maintaining system compliance while advancing State and Company decarbonization goals. In the FY 2022 plan, in coordination with its expected upcoming Grid Modernization Plan (GMP) filing, and in conjunction with negotiating the ISR Plan proposal with the Division, the Company is proposing to install feeder monitoring sensors at two substations and progress engineering at one substation. If the GMP is approved, the Company would move forward with full deployment of DER Enabling Investments (i.e., advanced field devices) on one substation. The DER Enabling Investments are included in the Advanced Field Devices category of spending in the GMP and are proposed in the Non-Discretionary category of the ISR Plan as the GMP has not been filed or approved by the Commission. The Company expects that if the GMP is approved, these DER Enabling Investments would continue to be proposed in the ISR and be classified as Discretionary spending in future ISR Plans.

Docket 4600 Analysis

The Electric ISR Plan is developed to advance many of the goals for the electric system that the Commission adopted in Docket No. 4600A – Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid, dated October 27, 2017 (the Guidance Document). These goals are:

- Provide reliable, safe, clean, and affordable energy to Rhode Island customers 19 over the long term (this applies to all energy use, not just regulated fuels);
- Strengthen the Rhode Island economy, support economic competitiveness, retain 2 and create jobs by optimizing the benefits of a modern grid and attaining 3 appropriate rate design structures;
- Address the challenge of climate change and other forms of pollution;
- Prioritize and facilitate increasing customer investment in their facilities 6 (efficiency, distributed generation, storage, responsive demand, and the 7 electrification of vehicles and heating) where that investment provides 8 recognizable net benefits;
- Appropriately compensate distributed energy resources for the value they provide 10 to the electricity system, customers, and society;
- Appropriately charge customers for the cost they impose on the grid;
- Appropriately compensate the distribution utility for the services it provides;
- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

See Docket 4600 Analysis included in Attachment 5.

FY 2022 Capital Investment Plan

The results of the system planning and work development process results in the Company's Capital Investment Plan that will enable it to continue to deliver safe, reliable, and efficient electric service for customers at reasonable costs. As such, we present the follow capital spending plan for FY 2022. As shown in Charts 8 and 9 below, the Company plans to invest $103.7 million to maintain the safety and reliability of its electric delivery infrastructure.

Chart 8
Capital Spending by Category FY 2012 – FY 2022

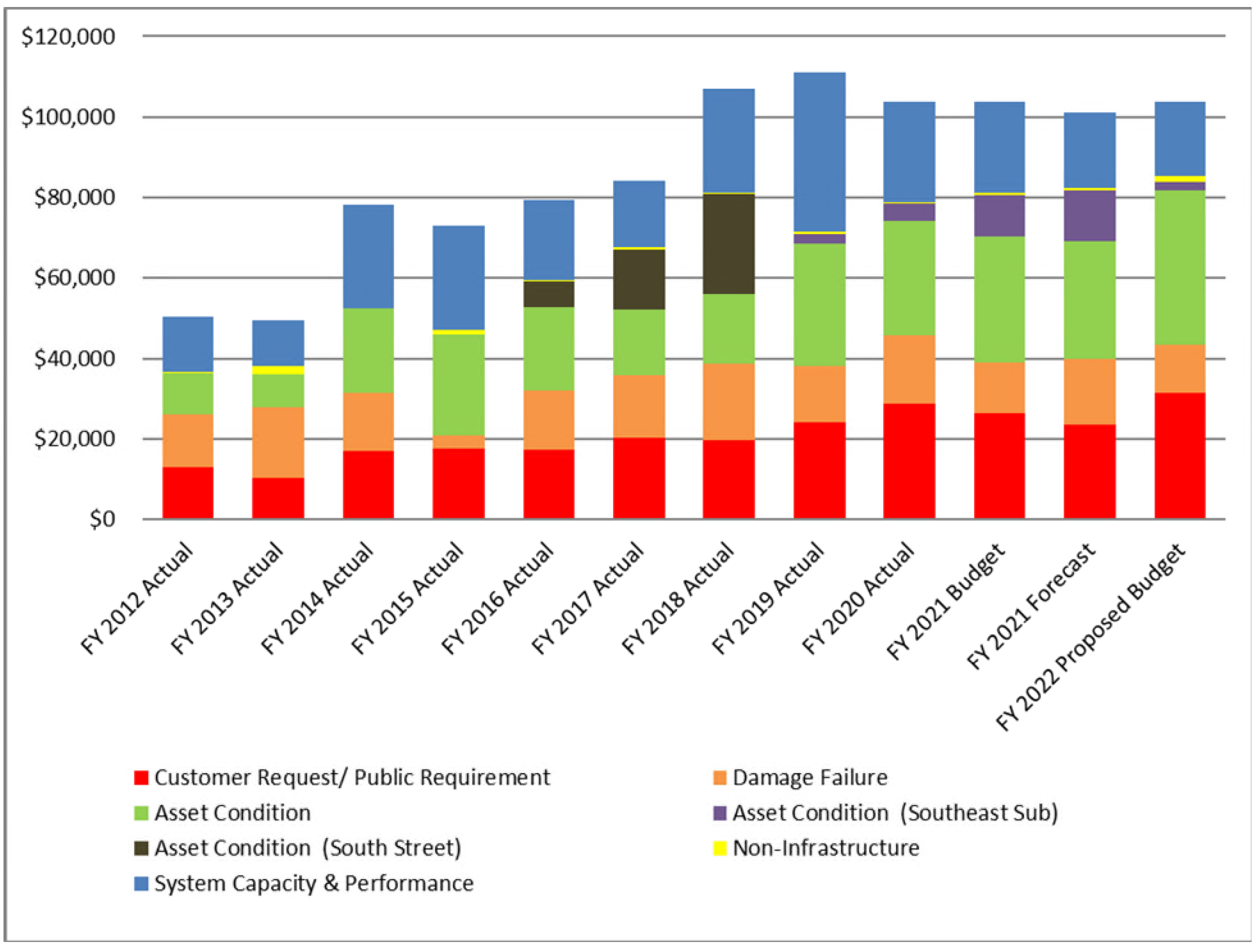


Chart 9
Capital Spending by Category FY 2012 – FY 2022
($000)

Spending Rationale	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Actual	FY 2019 Actual	FY 2020 Actual	FY 2021 Budget	FY 2021 Forecast	FY 2022 Proposed Budget
Customer Request/ Public Requirement	$13,075	$10,410	$17,138	$17,760	$17,412	$20,233	$19,627	$23,989	$28,667	$26,540	$23,483	$31,287
Damage Failure	12,993	17,515	14,374	3,044	14,531	15,614	19,184	13,999	17,028	12,365	16,323	12,198
Asset Condition	10,320	8,071	20,905	25,141	20,877	16,204	17,074	30,708	28,450	31,540	29,316	38,401
Asset Condition (Southeast Sub)	0	0	0	0	74	0	167	2,188	4,427	10,080	12,794	2,082
Asset Condition (South Street)	0	0	0	0	6,228	15,070	24,737	0	0	0	0	0
Non-Infrastructure	149	2,269	(346)	1,216	457	622	363	673	145	580	440	1,310
System Capacity & Performance	13,995	11,249	25,972	25,890	19,920	16,371	25,906	39,515	24,958	22,645	18,607	18,372
Total Capital Spending	**$50,532**	**$49,514**	**$78,043**	**$73,051**	**$79,499**	**$84,114**	**$107,058**	**$111,072**	**$103,676**	**$103,750**	**$100,964**	**$103,650**

Since a portion of the proposed capital spending in FY 2022 is for projects that will be completed over multiple years, the Company anticipates that only a portion of FY 2022 Plan spending will be placed in service in FY 2022. Likewise, a portion of the capital that will be placed in service in FY 2022 will also reflect prior years' capital spending for similar multiyear projects. Chart 10 below provides actual and forecasted Plant-in-Service additions for FY 2012 through the proposed FY 2022 Plan.

Chart 10
Plant-In-Service FY 2012 – FY 2022
($000)

Spending Rationale	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Actual	FY 2019 Actual	FY 2020 Actual	FY 2021 Target	FY 2021 Forecast	FY 2022 Target
Customer Request/ Public Requirement	$15,144	$11,262	$13,845	$18,443	$19,594	$14,959	$20,825	$24,011	$29,730	$21,210	$20,646	$28,045
Damage Failure	13,628	12,173	16,928	3,804	16,371	13,635	15,085	16,172	18,035	12,335	16,648	14,838
Asset Condition	13,019	6,638	14,640	28,094	18,533	18,726	44,645	36,599	23,870	38,948	46,504	39,098
Non-Infrastructure	60	113	1,990	346	111	0	3	0	194	566	440	1,102
System Capacity & Performance	9,799	14,145	8,727	25,970	16,845	28,170	12,103	34,461	33,081	37,435	26,488	16,430
Total Plant-in-Service Additions	**$51,650**	**$44,331**	**$56,130**	**$76,657**	**$71,453**	**$75,489**	**$92,660**	**$111,243**	**$104,909**	**$110,494**	**$110,726**	**$99,512**

Development of Work Plan and Estimating

Each year, the Company develops an Annual Work Plan, which is designed to achieve the Company's overriding performance objectives: safety, reliability, efficiency, and environmental responsibility. The Annual Work Plan represents a compilation of proposed spending for individual capital projects and programs. Projects and programs are categorized as follows: Customer Requests/Public Requirements, Damage/Failure, System Capacity and Performance, Non-Infrastructure, and Asset Condition. The proposed spending for each project or program is forecasted based on the most recent cost and timing estimates for in-progress projects and initial estimates for newly proposed projects.

This Electric ISR Plan presents the capital plan for FY 2022. It is the Company's best information regarding the investments it will need to make to sustain the safe, reliable, and efficient operation of the electric system. The Company continuously reviews and updates the capital plan during the year for changes in assumptions, constraints, project delays, accelerations, outage coordination, system operations, performance, safety, updated estimates, and customer-driven needs.

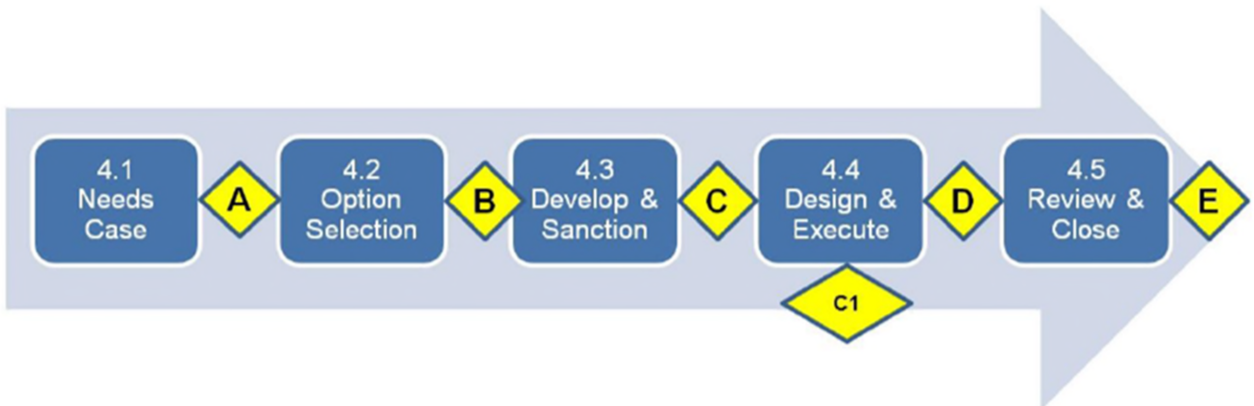
Once the mandatory budget level has been established for the Customer Request/Public Requirements and Damage/Failure spending categories, the Company reviews projects and programs in the System Capacity and Performance and Asset Condition categories for inclusion in the spending plan. A project risk score is assigned to each project and takes into account key performance areas such as safety, reliability, and environmental, while also accounting for criticality. While project risks score is a significant criterion, other factors considered in creating the Work Plan include, but are not limited to, new project or in-progress status, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed to optimize the cost efficiency and outage planning. The objective is to establish a capital portfolio that optimizes investments in the system based upon the measure of risk or improvement opportunity associated with a project. Historical and forward-looking checks are made to identify deviations from expected or historical trends.

The portfolio is presented to the Company's senior executives and approved by the President of The Narragansett Electric Company. The budget amount is approved on the basis that it provides the resources necessary to meet the business objectives set for that year. Company management is responsible for managing the approved budget.

Estimating Complex Projects Using the Stage-gate Process

The Company uses a stage-gate process for the creation, development and delivery of complex capital projects. The process breaks the typical project life cycle down into five stages as shown on the flowchart below.

Chart 11
Complex Capital Delivery Stage-Gate Process



It applies a "gate" for substantiating that the project is ready for advancement to the next stage and that it continues to support goals identified when the project was initially envisioned.

Stages and Estimate Refinement

Stage 4.1 Needs Case – Develop needs case based on system or customer-driven requirements. Determine high-level options based on system modelling. Identify opportunities to bundle scope. Identify the most viable option and a high-level estimate is entered into the five-year capital budget plan with iterative drafts as new information is added.

Stage 4.2 Option Selection – Review and analyze high-level options, comparing scope, cost, and risk to complete the project by the required date. Finalize consideration of opportunities to bundle scope. Select the preferred option - low cost fit for purpose option.

Stage 4.3 Develop & Sanction – Develop the preferred option to provide baseline scope, schedule, and cost for sanction. Develop plan for execution, resources, risk management, stakeholder management, and contract management. In addition to the Gate C review meeting, this Stage closes with the USSC Sanction Meeting which informs senior leadership to ensure the project is a good investment decision and the best solution for customers. Also, sanctioning achieves formal funding authorization.

Stage 4.4 Design & Execute – Provide the final design and implement contract strategy. Construct, test, and commission the preferred option.

- Stage 4.4a Design – Prepare the project for external bid or for internal construction. Finalized engineering designs are developed and approved for construction; long lead materials and permits are secured, and other plans and deliverables are further developed.
- Stage 4.4b Execute – Spans the construction activities from external and internal sourcing through testing and commissioning. At the end of this stage the project is fully operational and ready for closeout. Phased projects may go into this stage separately.
- Stage 4.5 Review & Close – Ensure the project is complete, all tasks and commitments are fulfilled, and costs are final. Archive project documents.

Estimates are prepared at Stage 4.1, 4.2 and 4.3. The refinement and accuracy of estimates differ at each of these stages. Projects that are at earlier stages in the project life cycle have estimates that are less refined and are more susceptible to change. Projects that are in progress or soon to be in progress have estimates that are more refined.

A cost contingency is a component of the estimate and varies based on where in the stage-gate process the estimate is being calculated. In Step 4.1 and 4.2, cost contingency is typically applied as a fixed amount (%) based on a qualitative assessment of the overall project risk. In Stage 4.3 and 4.4, cost contingency is based on identified risks and uncertainties calculated using probabilistic modelling.

Delegation of Authority and Sanctioning

Delegation of Authority (DOA) is a financial control and provides a framework to ensure that business decisions are made at an appropriate level with the right authority. For purposes of capital projects, that framework is the sanctioning process. In accordance with the Company's DOA governance policy, projects over $1.0 million require the preparation of a Project Sanction Paper (PSP) and presentation of that paper at the USSC Sanction Meeting at which senior leadership is informed of the project to ensure the project is a good investment decision and the best solution for customers. Also, sanctioning achieves formal funding authorization for the project. Projects under $1.0 million are authorized online. If, at any time, the anticipated or forecasted project cost exceeds DOA authorization, a request for additional funding must be made and the commitment must be authorized by a higher level of authority. A pilot project is underway increasing the PSP limit to $2.0 million. A decision will be made after evaluating the impacts of the pilot.

FY 2022 Proposed Capital Spending Plan

As shown in the table below, the Company plans to invest $103.7 million in FY 2022 to maintain the safety and reliability of its electric delivery infrastructure. The section below summarizes this spending by key driver and outlines the large projects and programs in the Plan. This spending level is approximately $100,000 lower than the Company's approved FY 2021 Electric ISR Plan of $103.8 million.

Chart 12
Capital Spend by Category FY 2012 – FY 2022
($000)

Spending Rationale	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Actual	FY 2019 Actual	FY 2020 Actual	FY 2021 Budget	FY 2021 Forecast	FY 2022 Proposed Budget
Customer Request/ Public Requirement	$13,075	$10,410	$17,138	$17,760	$17,412	$20,233	$19,627	$23,989	$28,667	$26,540	$23,483	$31,287
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Asset Condition (Southeast Sub)	0	0	0	0	74	0	167	2,188	4,427	10,080	12,794	2,082
Asset Condition (South Street)	0	0	0	0	6,228	15,070	24,737	0	0	0	0	0
Non-Infrastructure	149	2,269	(346)	1,216	457	622	363	673	145	580	440	1,310
System Capacity & Performance	13,995	11,249	25,972	25,890	19,920	16,371	25,906	39,515	24,958	22,645	18,607	18,372
Total Capital Spending	**$50,532**	**$49,514**	**$78,043**	**$73,051**	**$79,499**	**$84,114**	**$107,058**	**$111,072**	**$103,676**	**$103,750**	**$100,964**	**$103,650**

Attachment 1 to this section provides spending detail on major project categories that support the proposed level of capital spending by key driver shown in Chart 12 above. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available. Attachment 3 includes a summary of information regarding these major multi-year projects. This information may vary slightly from certain previous information provided because the Company continues to refine the project cash flows based on the best information available throughout the development of the Electric ISR Plan.

Summary of Investment Plan by Key Driver

Chart 13 below summarizes the planned spending level for each of the key driver categories of the Electric ISR Plan proposed for FY 2022.

Chart 13
Proposed FY 2022 Capital Spending by Key Driver Category
($000)

Spending Rationale	Proposed Budget	%
Customer Request/Public Requirement	$31,287	30.2%
Damage Failure	12,198	11.8%
Subtotal Non-Discretionary	43,485	42.0%
Asset Condition	38,401	37.0%
Non-Infrastructure	1,310	1.3%
System Capacity & Performance	18,372	17.7%
Subtotal Discretionary (excl SE Sub)	58,083	56.0%
Asset Condition - Southeast Substation	2,082	2.0%
Subtotal Discretionary (incl SE Sub)	60,165	58.0%
Total FY 2022 Capital Spending	**$103,650**	**100%**

The Company considers the investment required to comply with customer requests, statutory and regulatory requirements and to fix damaged or failed equipment as mandatory and non-discretionary in terms of scope and timing. Together, these items total approximately $43.5 million of FY 2022's proposed capital investment.

The Company considers the investment required to comply with asset condition, non-infrastructure, and system capacity and performance as discretionary in terms of scope and timing. The Company has slightly more discretion regarding the timing of the other categories and closely monitors the risk associated with delaying such projects due to the potential impact of the consequences of the failure of equipment or systems. The System Capacity and Performance, Asset Condition, and Non-Infrastructure projects and programs that the Company will pursue in FY 2022 have been chosen to minimize the likelihood of reliability issues and other problems due to under investment in the overall system. Together, these items total approximately $60.2 million of the proposed capital investments in FY 2022.

Customer Request/Public Requirements

As shown in Attachment 1, the Company has set a budget of $31.3 million to meet its Customer Request/Public requirements in FY 2022. This is $4.8 million higher than FY 2021 budget of $26.5 million due primarily to proposed $2.0 million for COVID related work and $2.7 million related to DER Enabling/Grid Modernization investments. Projects and programs in this category arise from the Company's regulatory, governmental, or contractual obligations. Overall, the scope and timing of this work is defined by those who are external to the Company.

Much of the construction work is variable and requested on short notice to account for emergent projects. The Company sets its budget based on data from previous fiscal years. Since the Company is reimbursed for a portion of this spending, the budget represents the capital the Company expects to spend, net of contributions in aid of construction (CIAC) and other reimbursements.

The chart below shows a comparison of FY 2022's spending to FY 2021's spending for the Customer Request/Public Requirements category.

Chart 14
Proposed FY 2022 Capital Spending – Customer Request / Public Requirement
($000)

Customer Request/Public Requirement Spending Rationale	FY 2021 Budget $	FY 2021 Budget %	FY 2022 Budget $	FY 2022 Budget %
New Business - Commercial	$8,405	32%	$9,066	29%
New Business - Residential	4,370	16%	4,020	13%
Public Requirements	2,670	10%	2,960	9%
Transformers & Related Equipment	4,200	16%	4,915	16%
Meters – Dist	2,745	10%	2,775	9%
Distributed Generation	1,000	4%	1,000	3%
DER - Non-Discretionary	2,000	8%	2,700	9%
COVID - WORK	0	0%	2,000	6%
Other	1,150	4%	1,851	6%
Total	**$26,540**		**$31,287**	

The major components in the Customer Request/Public Requirement category are:

- Responding to new customer requests, including establishing electric delivery service to new customers and customer Distributed Generation (DG) requests;
- Relocating facilities for public works projects requested by cities and towns and the Rhode Island Department of Transportation;
- Transformer, capacitor, regulator, network protectors and meter purchases and installations;
- Outdoor lighting requests and service;
- Strategic DER – The Company has proposed spending $2.7 million and considers this spending non-discretionary. See “Strategic DER Advancement and Grid Modernization” section under “System Planning”.
- COVID Work – See “COVID 19 Impacts and Analysis” section under “System Planning”.

Damage/Failure

For FY 2022, the Company is proposing a $12.2 million budget for costs to replace equipment that either unexpectedly fails or becomes damaged, which is $200,000 less than the prior year budget of $12.4 million. These projects are required to restore the electric distribution system to its original configuration and capability following damage from storms, vehicle accidents, vandalism, and other unplanned causes. In response to a recommendation made by the Division related to its review of the FY 2020 ISR, the Company undertook a review of its processes related to the Damage/Failure blanket. That review created refined definitions for Damage/Failure and Asset Replacement work. New processes have been established for FY

2021 and the Company is assessing how the refined definitions and process are impacting spending in this area and asset replacement.

Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historical trends. A portion of the Damage/Failure budget allows for larger project work that will arise within the current year as well as carryover projects from the prior fiscal year where the final restoration of the plant-in-service will not be completed until FY 2022. As in FY 2021, the budget set for FY 2022 also includes capital spending to address issues that have been identified for immediate repair as part of the I&M program described in Section 4.

The chart below shows a comparison of FY 2022's spending to FY 2021's spending for the Damage/Failure category.

Chart 15
Proposed FY 2022 Capital Spending – Damage/ Failure
($000)

Damage/Failure Spending Rationale	FY 2021 Budget $	FY 2021 Budget %	FY 2022 Budget $	FY 2022 Budget %
Damage/ Failure	$9,740	79%	$9,528	78%
Reserves - DF	900	7%	920	8%
Major Storms – Dist (includes Reserves)	1,725	14%	1,750	14%
Total	**$12,365**		**$12,198**	

The major components of the Damage/Failure category are:

- Blanket projects for substation and/or line failures for small dollar frequently occurring items or those assets whose size is unknown at the time of the failure.
- A reserve to address larger failures that require capital expenditures in excess of $100,000. The budget for this item is built on recent historical trends of such items and allows the Company to complete unplanned work without having to halt work.
- Major storm activity affects the Company's assets. While the actual spend in this category may vary greatly, this reserve allows the Company to avoid removing other planned work from the capital program when replacement of assets due to weather is required.

Asset Condition

The Company is proposing a $40.5 million budget for FY 2022 to replace assets due to condition issues. This level is $1.1 million less than the $41.6 million budgeted for FY 2021. Projects and programs in the spending category have been identified to reduce the risk and consequences of unplanned asset failures and are identified as part of the System Planning process. The focus is to identify specific susceptibilities (failure modes) and develop alternatives to avoid such failure modes. The investments required to address these situations are essential, and the Company schedules these investments to minimize the potential for reliability issues. Moreover, the large number of aged assets in the Company's service area requires the Company to develop strategies to replace assets if their condition impairs reliable and safe service to customers. Experience with assets that have poor operating characteristics in the field has led the Company to develop strategies to remove such equipment. The investments made in these assets are prioritized based on their likelihood of failure along with consequences of such an event.

The chart below shows a comparison of FY 2022's spending to FY 2021's spending for the Asset Condition category.

Chart 16
Proposed FY 2022 Capital Spending – Asset Condition
($000)

Asset Condition Spending Rationale	FY 2021 Budget $	FY 2021 Budget %	FY 2022 Budget $	FY 2022 Budget %
Large Projects:				
Dyer Street	$7,160	17%	$9,717	24%
Prov LT Study - Ph1A	2,800	7%	4,966	12%
Prov LT Study - Ph1B	1,440	3%	3,390	8%
Southeast	10,080	24%	2,082	5%
Other Projects and Programs:				
Underground Cable projects	8,500	20%	9,700	24%
Blanket projects	4,480	11%	3,592	9%
I&M	2,900	7%	3,000	7%
Substation Breakers & Reclosers	1,805	4%	2,390	6%
Other projects and programs	2,455	6%	1,646	4%
Total	**$41,620**		**$40,483**	

The major projects and programs in the Asset Condition category are

- *Admiral Street* – The Providence Area Planning Study identified various asset condition issues within the study area including five indoor substations and over 25 miles of underground cable. The study recommended the expansion of the 12.47 kV distribution system to enable conversion of the majority of 11.5 kV and 4.16 kV load. This allows the elimination of several 4.16 kV and 11.5 kV indoor and outdoor stations and miles of sub-transmission cable. A large part of the 12.47 kV capacity in the area would be provided by a new 115/12.47 kV station at Admiral Street. The proposed 115/12.47 kV Admiral Street substation would be used to supply the converted load from the Geneva, Harris Avenue, Olneyville, and Rochambeau Avenue substations. The recommendations from the Providence Area Planning Study have been categorized into four phases summarized below:

- Phase 1A – Rebuild and convert sixteen 4 kV and 11 kV feeders within Providence to 12.47 kV. Lines will be fed from the 12.47 kV Clarkson and Lippitt Hill substations to allow loads to be removed from Admiral Street in order to implement Phase 1B.
- Phase 1B – Convert 4 kV lines currently fed from Olneyville to 12.47 kV. Install manholes and ductbanks for new 12.47 kV feeds from Admiral Street station. Remove the 4 kV and 11 kV equipment from Admiral Street building and demolish building. Install new 12 kV equipment and building at Admiral Street, energize new 12.47 kV feeders.
- Phase 2 – Rebuild and convert sixteen 4 kV and 11 kV feeders at Olneyville, Harris Avenue, Rochambeau and Geneva substations. Loads will be carried by new Admiral Street 12.47 kV substation.
- Phase 3 – Retire the 4 kV and 11 kV indoor and outdoor substations at Olneyville, Harris Avenue, Rochambeau and Geneva substations.
- Phase 4 – Install a 115 / 12.47 kV substation at Knightsville, convert the station feeds to 12.47 kV, and remove and retire the existing 23 / 4.16 kV station.

- *Dyer Street Replace Indoor Substation* – The new recommended plan proposes installing a new 11.5 kV-4.16 kV substation within the existing South Street substation outdoor yard. The Providence Long-term Study (2015) recommended the replacement of the Dyer Street 4.16 kV and 11 kV indoor substation due to asset condition. As previously communicated, the Company paused this project towards the end of FY 2020 to re-assess options as costs were estimated to be significantly higher than originally estimated. The recommended plan was recently changed due to avoid substantial increases in cost for the original plan as well as complexities involved in historical building rehabilitation. In FY 2022, the Company proposes capital spending to finalize the design, purchase materials and start construction. As shown in Attachment 3, this is a multi-year project with capital spending in future fiscal years.
- *Southeast Substation* – This project addresses asset condition and safety concerns at the Pawtucket No. 1 and the Dunnell Park substations as well as improvements to overall capacity. This is a significant multi-year project. It is anticipated that the Dunnell Park substation will be put in service in early calendar year 2021 and will wind down during FY 2022. The Company will continue to track this project separately and report on its progress quarterly.
- *Inspection & Maintenance Program* **–** Section 4 includes details related to both the capital and O&M components of the I&M program.
- *The Substation Circuit Breaker and Recloser Program* **–** This program targets obsolete and unreliable breaker facilities. The Company has approximately over 1,000 distribution

substation circuit breakers and reclosers in substations that it maintains, refurbishes, and replaces as necessary. The Company has specifically identified units with obsolete technology, such as air magnetic interruption, for replacement. Additionally, where cost-effective and where conditions warrant, the Company bundles work and replaces disconnects, control cable, and other equipment associated with these circuit breakers.

- *Recloser Replacement Program* – The purpose of this program is to address safety, reliability, and asset condition issues related to Form 3A reclosers and to address worker safety and system reliability issues related to G&W Viper reclosers of a certain vintage. The remaining reclosers in the Form 3A program will be addressed in FY 2022 and program closure activities will be completed in FY 2022. The Company plans to replace approximately four G&W Viper units per year from FY 2022 through FY 2024.
- *Underground Cable Replacement Program* **–** This program implements the strategy to replace primary underground cable that is either in poor condition or has poor operating history. This program targets known problematic cable types such as paper and lead insulated cables and certain cross-linked polyethylene (XLPE) insulated cables. The Company's present underground cable replacement program is a combination of reactive fix-on-fail replacement in the Damage/Failure spending rationale and proactive replacement in the Asset Condition spending rational based on type of construction, asset condition, and failure history for a specific or similar asset. Discretionary spending for proactive replacement is also work justified by the need to eliminate repeated in-service failures, anticipated end-of-life based on historic performance or industry experience, or

other operational issues. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. The underground cable replacement program prioritizes the cables using a risk matrix focused on cable characteristics. The Company's goal for the FY 2022 Plan is to return to spending levels recommended in the underground cable replacement program.

- *URD Cable Program* – This strategy applies to Underground Residential Development (URD) and Underground Commercial Development (UCD) cables sized #2 and 1/0 and does not apply to mainline or supply cables. These cables are replaced or rehabilitated through cable injection. This strategy supports the current method for handling cable failures by fixing immediately upon failure and offers options for managing cables that have sustained multiple failures. Although interruptions on #2 and 1/0 cables do not significantly influence Company level service quality metrics, they can have significant localized impacts on effected neighborhoods. For URDs with at least three cable failures within the last three years, two options are considered for replacement. Insulation injection is identified as the preferred solution for direct buried Cross Linked Polyethylene cables in a loop fed arrangement. The overall condition of the primary and neutral cables and installation specifics will determine if insulation injection is a viable option.
- *Network Blower Motor Program* – This program replaces network vault blower motors with arc resistant motors. By the end of FY 2021, approximately 60 network vault blower motors will exist in the Rhode Island underground electric system, predominantly

located in Pawtucket and Providence. Approximately 25 locations with blower motors will require civil work to allow installation of the Company's standard arc resistant motor and vent system.

- *Distribution Substation Battery Replacement Program* – Battery systems play a significant role in the safe and reliable operation of substations. The batteries and chargers provide direct current power for protection, control, and communications within the substation, as well as communication between the substation and the Company's operational control center. Program goals include the replacement of batteries that are 20 years or older and ensuring that battery systems meet the current operating requirements and perform their designed functions. In FY 2022, the Company plans to replace 2 station batteries as it optimizes the replacement schedule with risks and upcoming projects.
- *Blanket Projects* – In addition to specific projects, the Company also has asset replacement blanket projects established to ensure that local field engineering and operations can resolve asset condition issues (i.e., deteriorated equipment) in an efficient and effective manner. These individual work requests have a value of less than $100,000. The amount of funding in the blanket project is reviewed and approved each year based on historical trends in the volume of work required, input from local Operations, and a forecasted impact of inflation on material and labor rates. Current year spending is monitored on a monthly basis.

System Capacity and Performance

For FY 2022, the Company is proposing a budget of $18.4 million for System Capacity and Performance projects, which is $4.3 million less than the FY 2021 budget of $22.6 million. The Company has minimal discretion to address load constraints caused by the existing and growing and/or shifting demands of customers.

Projects in this category identified as part of the Company's planning processes, which is conducted to identify thermal capacity constraints, maintain adequate delivery voltage, and assess the capability of the network to respond to contingencies that might occur. As previously noted, the forecasted growth rates from the base case load forecast are applied to each of the substations and feeders within the area. Distribution planners then adjust forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfigurations. The planners use the forecasted peak loads for each feeder/substation under the extreme weather scenario to perform planning studies and to determine if the thermal capacity of its facilities is adequate.

Individual project proposals are identified to address planning criteria violations. At a conceptual level, the Company prioritizes these project proposals and submits them for inclusion in future capital work plans. Projects in the load relief program are typically new or upgraded substations and distribution feeder mainline circuits. Other projects in this program are designed to improve the switching flexibility of the network, improve voltage profile, or to release capacity through improved reactive power support.

These investments are required to ensure that the electric network has sufficient capacity to meet the demands of customers and to maintain the requisite power quality required by customers. Generally, projects in this category address loading conditions on substation transformers and distribution feeders to comply with the Company's system and capacity loading policy and are designed to reduce degradation of equipment service lives due to thermal stress. These types of projects are also designed to provide appropriate degrees of system configuration flexibility to limit adverse reliability impacts of large contingencies. It is important to recognize that these projects may also have asset condition drivers that influence replacement decisions.

The chart below shows a comparison of FY 2022's spending to FY 2021's spending for the System Capacity and Performance category.

Chart 17
Proposed FY 2022 Capital Spending – System Capacity and Performance
($000)

System Capacity and Performance Spending Rationale	FY 2021 Budget $	FY 2021 Budget %	FY 2022 Budget $	FY 2022 Budget %
Large Projects:				
Aquidneck Island	$13,485	60%	$6,434	35%
New Lafayette Substation	390	2%	1,857	10%
Warren Substation	465	2%	621	3%
East Providence Substation	1,550	7%	731	4%
Other Projects and Programs:				
Volt/Var	1,135	5%	3,227	18%
EMS/RTU	980	4%	1,300	7%
3VO	540	2%	1,435	8%
Strategic DER	1,700	8%	0	0%
Blanket Projects - SCP	1,385	6%	1,730	9%
Other projects and programs	1,015	4%	1,037	6%
Total	**$22,645**		**$18,372**	

The major projects and programs in the System Capacity and Performance category are:

- *Aquidneck Island Projects:* The southern portion of Aquidneck Island is supplied by a highly-utilized supply and distribution system. This 23 kV supply system and 4.16 kV distribution system has limited capacity to supply load growth and new spot loads, and it is becoming increasingly challenging to supply large spot loads in southern Middletown and in the City of Newport.

- *Newport Substation:* This construction of a new 69/13.8 kV substation and related line work to provide load relief to the City of Newport is complete and in service.
- *Jepson Substation:* This project involved rebuilding the Jepson substation in Middletown. The majority of the assets are forecasted to be placed into service in FY 2021.
- *Dexter Substation:* This project began in October 2020 and includes the use of a mobile substation in lieu of the substation during demolition and reconstruction. Planned completion is March 2021. The mobile substation will be removed in FY 2022.
- *Various Distribution Circuits:* This portion of the project consists of various distribution circuits upgrades throughout Newport, Middletown, and Portsmouth towns to improve reliability.
- *Various Substation Retirements and minor Improvements:* The North Aquidneck, South Aquidneck, Bailey Brook, & Vernon Substations will start the process of retirement. The Harrison, Merton, & Kingston Substations will start the design process for minor improvements. These substations are planned to be completed by the end of FY 2023.

- *East Providence Substation:* The East Bay Long Term Study identified asset condition and loading concerns in the East Providence area. The study proposed a new station in the East Providence area that will reduce the loading and dependence on the 23 kV sub-transmission system. This project involves the construction of a new 115/12.47 kV substation adjacent to the 115 kV transmission right-of-way. Construction will consist of One 40 MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, six feeder positions, and two One 7.2 MVAR two-stage capacitor banks. The Company proposes spending to progress preliminary engineering and procurement on this project in FY 2022.

- *Warren 115/12.47 kV Substation:* The Warren #5 substation expansion project has been recommended as part of the East Bay Long Term Study. The project expands the existing substation by creating two new 12.47 kV feeder positions, a new substation capacitor, and new distribution construction to provide additional capacity to the Warren and Barrington municipalities. Completion of the project also facilitates the retirement of the Barrington substation, which has safety and asset condition concerns, the capacity constrained Mink 115/23 kV substation, and a significant portion of the 23 kV sub-transmission in the area. The Company proposes spending to progress preliminary engineering in FY 2022.
- *New Lafayette Substation:* A comprehensive study of the South County East area was performed to identify existing and potential future distribution system performance concerns. The study identified several reliability and asset condition issues. The study recommends building a new open air, low profile, breaker-and-one-half 115/12.47 kV substation at the existing Lafayette substation site. The existing 34.5/12.47 kV station at Lafayette will be retired once the new station is in-service. In FY 2022 the Company proposes spending on engineering, design activities and advanced construction work to

create efficiencies by combining certain types of work, such as, including the development of the site, storm water management system, and fencing shared with the Wickford Junction station that will reside on the same parcel.

- S*ubstation EMS/RTU (SCADA) Additions Program:* The Company is proposing to expand the EMS/RTU program to improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies.
- *Volt/VAR Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion*: The Company continues to deploy VVO/CVR on targeted feeders where it is cost beneficial to do so. The intent of this project is to flatten and lower the feeder voltage profile using additional voltage monitors along the feeder and centralize control of the regulating devices based on real time system performance. The lowering of feeder voltages benefits customers by reducing the demand and energy usage. As discussed in Section 4, this project has ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing.
- *3V0 Program:* As DG penetration levels continue to increase, the need for zero sequence overvoltage (3VO) protection is more necessary. The addition of DG to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. To enable a more rapid response to DG interconnections, the Company proactively installs 3V0 protective devices in substations on a priority basis. In existing stations, this work can be complex, sometimes requiring high voltage yard rearrangement of an extensive duration.

- *Blanket Projects:* In addition to specific projects, the Company also has blanket projects that are established to ensure that local field engineering and operations can resolve system and equipment loading and reliability issues in an efficient and effective manner. The individual work requests have a value of less than $100,000 in value. The amount of funding in the blanket project is reviewed and approved each year based on the results of annual capacity planning and reliability reviews, historical trends in the volume of work required, input from local Operations, and forecasted impacts of inflation. Current year spending is monitored on a monthly basis.

Non-Infrastructure Spending

The non-infrastructure category is for those capital expenditures that do not fit into one of the above-mentioned categories. This capital spending is necessary to run the electric system, such as general and telecommunications equipment. In FY 2022 the Company has proposed a budget of $1.3 million. The proposed increase of $0.8 million in capital spending is related to the required purchase and installation of communication equipment for substations due to the retirement of certain communication circuits.

Recovery of Electric ISR Plan Capital Investment – Capital Placed-In-Service

The Company calculates the revenue requirement based on the projected capital amounts to be placed into service plus associated Cost of Removal (COR). To develop its Capital Placed-In-Service figure for this filing, the Company used estimated timing of in-service dates for capital spending being placed into service during FY 2022. Each year, as part of the Company's annual reconciliation, the revenue requirement related to discretionary in-service amounts is trued-up based on the lesser of allowed discretionary capital spending or actual capital investment placed into service on a cumulative basis since the inception of the Electric ISR Plan. The discretionary categories include the Asset Condition, Non-Infrastructure, and System Capacity and Performance categories. Because of the multi-year nature of certain projects, current and prior year(s) capital spending was included in the Capital Placed-In-Service amount when a project is placed into service during the fiscal year. Similarly, the capital portion of a project included in a fiscal year's spending plan that will be placed into service in future fiscal periods was included in subsequent revenue requirement calculations during that project's in-service year.

Chart 18 below provides details regarding the total FY 2022 proposed amounts for Capital Spending, Capital Placed-in-Service, and COR that have been used to develop the FY 2022 Electric ISR Plan revenue requirement.

Chart 18
Proposed FY 2022 Proposed Capital Spending, Capital Placed-in-Service, and COR
($000)

Spending Rationale	FY 2022 Capital Spending	FY 2022 Plant in Service	FY 2022 COR	Capital Placed-in-Service + COR
Customer Request/Public Requirement	$31,287	$28,045	$2,966	$31,011
Damage Failure	12,198	14,838	1,942	16,780
Subtotal Non-Discretionary	43,485	42,882	4,908	47,790
Asset Condition	40,483	39,098	6,927	46,025
Non-Infrastructure	1,310	1,102	23	1,125
System Capacity & Performance	18,372	16,430	2,742	19,172
Subtotal Discretionary	60,165	56,630	9,692	66,321
Total Capital Investment in Systems	**$103,650**	**$99,512**	**$14,600**	**$114,112**

Attachment 1 – Capital Spending by Key Driver Category and Budget Classification

Spending Rationale	Budget Classification	FY 2011 Actual	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual	FY 2015 Actual	FY 2016 Actual	FY 2017 Actual	FY 2018 Actual	FY 2019 Actual	FY 2020 Actual	FY 2021 Budget	FY 2021 Forecast	FY 2022 Budget
Customer Requests/ Public Requirements	3rd Party Attachments	($910)	$464	$223	$141	$271	$290	$160	$123	$400	$186	$200	$522	$281
	Distributed Generation	0	0	(675)	195	981	(933)	3,760	280	1,815	1,568	1,000	1,000	1,000
	Land and Land Rights	281	185	128	94	165	143	199	305	360	350	385	358	393
	Meters - Dist	2,215	1,497	1,455	835	612	2,935	1,844	2,627	2,332	2,530	2,995	2,111	3,375
	New Business - Commercial	4,287	3,391	3,722	4,957	4,781	7,568	7,815	5,625	7,293	8,702	8,405	8,065	9,066
	New Business - Residential	3,530	2,833	2,886	3,593	3,769	5,085	4,598	4,618	4,337	5,186	4,370	1,767	4,020
	Outdoor Lighting - Capital	411	495	488	758	479	129	144	185	455	667	315	300	577
	Public & Regulatory Requirements	1,539	1,135	(1,231)	4,234	4,214	770	(124)	3,078	2,495	4,320	2,670	2,747	4,960
	Strategic DER Investments	0	0	0	0	0	0	0	0	0	0	2,000	2,413	2,700
	Transformers & Related Equipment	3,278	3,075	3,415	2,331	2,488	1,425	1,837	2,786	4,503	5,157	4,200	4,200	4,915
Cust Req/ Public Req Total		**14,631**	**13,075**	**10,410**	**17,138**	**17,760**	**17,412**	**20,233**	**19,627**	**23,989**	**28,667**	**26,540**	**23,483**	**31,287**
Damage/Failure	Damage/Failure	8,331	9,574	7,795	11,228	12,284	11,327	13,594	11,426	10,087	12,764	10,640	11,487	10,448
	Major Storms - Dist	4,863	3,419	9,720	3,146	(9,240)	3,204	2,020	7,758	3,912	4,264	1,725	4,836	1,750
Damage/Failure Total		**13,194**	**12,993**	**17,515**	**14,374**	**3,044**	**14,531**	**15,614**	**19,184**	**13,999**	**17,028**	**12,365**	**16,323**	**12,198**
Asset Condition	Asset Replacement	5,604	9,767	6,984	14,011	16,478	15,957	12,339	14,449	29,984	25,487	28,140	26,416	35,401
	Asset Replacement - Southeast Sub	0	0	0	0	0	74	0	167	2,188	4,427	10,080	12,794	2,082
	Asset Replacement - South Street	0	0	0	0	0	6,228	15,070	24,737		1,016		0	
	Asset Replacement - I&M (NE)	227	553	1,086	6,681	7,593	4,811	3,022	1,282	712	1,894	2,900	2,900	3,000
	Safety & Other	0	0	0	213	1,069	110	844	1,345	13	53	0	0	
Asset Condition Total		**5,831**	**10,320**	**8,070**	**20,905**	**25,140**	**27,179**	**31,274**	**41,980**	**32,897**	**32,877**	**41,120**	**42,110**	**40,483**
Non-Infrastructure	Corporate/Admin/General	645	118	890	(1,245)	408	(61)	86	38	251	(248)	0		
	General Equipment - Dist	61	149	191	395	697	331	383	207	219	166	330	194	250
	Telecommunications Capital - Dist	0	0	1,188	504	112	187	153	117	203	228	250	247	1,060
Non-Infrastructure Total		**706**	**267**	**2,269**	**(346)**	**1,217**	**457**	**622**	**362**	**673**	**145**	**580**	**440**	**1,310**
System Capacity & Performance	Load Relief	6,012	8,837	6,619	22,762	20,837	16,491	13,800	21,497	36,545	22,149	15,410	14,004	9,643
	Strategic DER Investments	0	0	0	0	0	0	0	0	0	0	1,700	1,038	
	Reliability	2,799	2,554	3,723	3,210	5,053	3,429	2,571	4,408	2,970	2,809	6,035	3,565	8,729
	Reliability - Feeder Hardening	1,984	2,564	907	0	0	0	0	0	0	0	0		
Syst Cap & Perf Total		**10,795**	**13,955**	**11,249**	**25,972**	**25,890**	**19,920**	**16,371**	**25,905**	**39,515**	**24,958**	**23,145**	**18,607**	**18,372**
Grand Total		**$45,157**	**$50,610**	**$49,514**	**$78,043**	**$73,051**	**$79,499**	**$84,114**	**$107,058**	**$111,072**	**$103,676**	**$103,750**	**$100,964**	**$103,650**

Attachment 2 – Project Detail for Capital Spending

Spending Rationale	Project #	Project Description	FY 2022
Customer Request/Public Requirement	COS0022	Ocean St-Dist-3rd Party Attch Blnkt	281
	C051909	PS&I DIST GEN RI.	1,000
	COS0091	Land and Land Rights RI Elect	393
	C083649	RI Landline Meter Replacement	400
	C085793	RI Meter Reprogramming	200
	CN04904	Narragansett Meter Purchases	1,975
	COS0004	Ocean St-Dist-Meter Blanket	800
	C046977	Reserve for New Business Commercial	2,850
	C083870	NARBAYCOM_NewSvc_PawtucketRI	285
	COS0011	Ocean St-Dist-New Bus-Comm Blanket.	5,931
	C046978	Reserve for New Business Residentia	300
	COS0010	Ocean St-Dist-New Bus-Resid Blankt	3,720
	COS0012	Ocean St-Dist-St Light Blanket.	577
	C046970	Reserve for Public Requirements Uni	1,760
	COS0013	Ocean St-Dist-Public Require Blnkt	1,200
	C085812	Covid Scenario Analysis Work RI	2,000
	C085910	Strategic DER Advancement - Advanced Devices	2,700
	CN04920	Narragansett Transformer Purchases	4,915
Customer Request / Public Requirements Spending Total			**31,287**
Damage/Failure	COS0014	Ocean St-Dist-Damage&Failure Blnkt	8,925
	COS0002	Ocean St-Dist-Subs Blanket.	603
	C046986	Reserve for Damage/Failure Unidenti	160
	C051608	Reserve for Damage/Failure Substati	760
	C022433	OSD Storm Cap Confirm Progrm Proj	1,750
Damage/Failure Total			**12,198**

Attachment 2 – Project Detail for Capital Spending

Spending Rationale	Project #	Project Description	FY 2022
Asset Condition	C032019	Batts/Chargers NE South OS RI	150
	C036527	Westerly Flood Restoration (D-Sub)	(2)
	C047378	IRURD Willowbrook	363
	C047394	IRURD Tanglewood	650
	C047829	IRURD High Hawk	17
	C049356	IRURD Silver Maple Phase 2	151
	C049462	"IRURD SIGNAL RIDGE, EAST GREENWICH	738
	C050070	IRURD Placeholder RI	(212)
	C050299	IRURD Eastward Look	168
	C051205	Dyer St replace indoor subst D-SUB	4,432
	C051211	Dyer St replace indoor subst D-LINE	5,285
	C051212	South St repl indoor subst D-SUB	300
	C051213	South St repl indoor subst D-LINE	(3)
	C055215	Westerly Flood Restoration (D-Line)	(2)
	C055343	RI UG Cable Placeholder	895
	C055359	RI UG Cable Repl Program - Fdr 79F1	220
	C055364	RI UG Cable Repl Program - Fdr 13F6	338
	C055370	RI UG Cable Repl Prog Fdr 1144/1109	460
	C055371	RI UG Cable Repl Prog Fdr 1142/1105	427
	C055392	RI UG Cable Repl Program - Secondar	500
	C056947	IRURD Juniper Hills WWarwick	374
	C057882	IRURD Chateau Apts URD Rehab	166
	C057903	IRURD Western Hills Village URD-	(2)
	C057906	IRURD Woodvale Estates URD-	15
	C058045	IRURD-Tockwotton Farm_TF Road.	170
	C058046	IRURD-Tockwotton Farm_RM Way.	(3)
	C065830	Recloser Replacement Program RI	200
	C069166	Pawtucket 1 Breaker Replacement	25
	C074307	RI UG 79F1 duct Charles & Orms Sts	729
	C076289	IRURD Pequaw Honk URD RI-L Compton	234
	C078474	Franklin Sq Sub_1105 & 1109 NW	440
	C078488	RI DFP100 Relay Replacement Project	40
	C078734	Ph 1A - ProvStudy Admiral St 4&11kV Convert	3,743
	C078735	Ph1B - ProvStudy New Admiral St 12kV D-Sub	1,438
	C078796	Ph1B - ProvStudy Admiral St-Rochamb D-Line	210
	C078797	Ph1B - ProvStudy Admiral St-Rochamb D-Sub	501
	C078800	Ph 1A - ProvStudy Clarkson-Lippit12kV DLine	1,223
	C078802	Ph 1B - ProvStudy Olneyville 4kV D-Line	204
	C078803	Ph 1B - ProvStudy Admiral St 12kV MH&Duct	272
	C078804	Ph 1B - ProvStudy Admiral St 12kV Cables	271
	C078805	Ph 4 - ProvStudy Knightsville 4kV Convert	220
	C078806	Ph 4 - ProvStudy Knightsville 4kV D-Sub	275

Attachment 2 – Project Detail for Capital Spending

Spending Rationale	Project #	Project Description	FY 2022
Asset Condition	C078921	RI UG Cable Repl Program - Fdr 1158	13
	C078923	RI UG Cable Repl Program - Fdr 1160	300
	C078926	RI UG Cable Repl Program - Fdr 1162	280
	C078928	RI UG Cable Repl Program - Fdr 1164	13
	C078931	RI UG Cable Repl Program - Fdr 1166	418
	C079331	Viper Recloser Replacement Pgm 1-RI	165
	C081006	Franklin Sq Breaker Replacement	1,804
	C081341	IRURD Woodland Manor-Coventry	481
	C082439	Franklin Sq-Replace 11kV Sub Equip	49
	C086514	RI GE Type U Bushing Replacement	275
	C083782	Replace 12.47 Breakers Drumrock 14	196
	C084172	IRURD Jencks Hill, Lincoln RI	270
	C084377	IRURD Governor's Hills, RI	403
	C084378	IRURD Frenchtown Green, RI	254
	C084965	IRURD Sandy Point Farms Phase 2	463
	C085005	RI UG Cable Repl Program - Fdr 1139	409
	C085553	RI Repl ACNW Vault Vent Blowers	400
	COS0017	Ocean St-Dist-Asset Replace Blankt	3,399
	COS0026	OS-Dist-Substation Asset Repl Blnk	193
	C026281	I&M - OS D-Line OH Work From Insp.	2,875
	C080076	I&M - OS Sub-T OH Work From Insp	125
	C053657	Southeast Substation (D-Sub)	787
	C053658	Southeast Substation (D-Line)	1,060
	C055683	Pawtucket No 1 (D-Sub)	235
Asset Condition Total			**40,483**

Spending Rationale	Project #	Project Description	FY 2022
Non-Infrastructure	COS0006	Ocean St-Dist-Genl Equip Blanket	250
	C086391	Verizon Copper to Fiber Conversions	800
	C040644	Telecom Small Capital Work - RI	260
Non-Infrastructure Total			**1,310**

Attachment 2 – Project Detail for Capital Spending

Spending Rationale	Project #	Project Description	FY 2022
System Capacity & Performance	C028628	Newport SubTrans & Dist Conversion	5,040
	C046726	East Providence Substation (D-Sub)	407
	C046727	East Providence Substation (D-Line)	325
	C054054	Jepson Substation (D-Line)	24
	C058310	Harrison Sub Improvements (D-Sub)	205
	C058401	Merton Sub Improvements (D-Sub)	190
	C058404	Kingston Sub Improvements (D-Sub)	325
	C065166	Warren Sub Expansion (D-Sub)	100
	C065187	Warren Sub Expansion (D-Line)	521
	CD00656	Jepson Substation (D-Sub)	650
	C081675	New Lafayette 115/12kV (D-Sub)	1,627
	C081683	New Lafayette 115/12kV (D-Line)	230
	COS0016	Ocean St-Dist-Load Relief Blanket.	335
	C005505	IE - OS Dist Transformer Upgrades	700
	C013967	PS&I Activity - Rhode Island	100
	C054090	"Reconductor Anthony Road, Foster R	59
	C059663	Cutout Mnted Recloser Program_RI	133
	C059882	Flood Contingency Plan NECO - D	45
	C074427	EMS Expansion - Phillipsdale 20	87
	C074428	EMS Expansion - Wampanoag 48	109
	C074430	EMS Expansion - Wood River 85	301
	C074431	EMS Expansion - Bonnet 42	99
	C074433	Bristol 51 - EMS and breaker rplmt	604
	C074438	EMS Expansion - Merton 51	104
	C075546	Farnum 105 EMS intallation	(2)
	C079494	Peacedale 3V0 D-Sub	400
	C080894	RI VVO Exp - Farnum Pike 123 Dist	936
	C080897	RI VVO Exp - Pontiac 27 Dist	695
	C080898	RI VVO Exp - Farnum Pike 23 Dist	400
	C080901	RI VVO Exp - Pontiac 27 Sub	575
	C084731	RI VVO Expansion - Woonsocket 26	15
	C085038	CHOPMIST 3V0 D-SUB	81
	C085276	PUTNAM PIKE 3V0 D-SUB	43
	C08TBD1	Natick 3V0 D-SUB	500
	C08TBD2	WAMPANOAG 3V0 D-SUB	80
	C08TBD3	Highland Park 3V0 D-SUB	80
	C085540	ELDRED 3V0 D-SUB	125
	C085628	RI Mobile 3V0 Units	125
	C085688	RI- VVO Putnam Pike	562
	C085689	RI VVO Putnam Pike	45
	COS0015	Ocean St-Dist-Reliability Blanket.	1,262
	COS0025	OS-Dist-Substation LR/Rel Blnkt	133
System Capacity & Performance Total			**18,372**
FY 2022 Capital Spending Total			**103,650**

Attachment 3 – See Also Excel Version

		ISR GROUPING	MAJOR PROJECT: CURRENT PHASE & TYPE OF ESTIMATE	Total Current Estimate (Distribution)	Initial Estimate at time of First Sanction	Date of Last Sanction (partial or full)	Estimated Construction Start (earliest portion)	Estimated Construction End (last portion)	Prior Years Actual Capital Spend	FY 2021 FYTD Actual Capital Spend ($-MTD)	FY 2021 Capital Forecast (6+6 DRAFT)	FY 2021 ISR Capital Budget	FY 2022 Capital Budget (Prelim)	FY2022 PLAN ADJ'TS	FY2022 Capital Budget ADJUSTED	FY2023 Capital Budget	FY2024 Capital Budget	FY2025 Capital Budget	FY2026 Capital Budget
Discretionary - System Capacity & Performance	Major Projects	Aquidneck Island	Phase: Final Cutovers & Project Closeout, Estimate +/- 10%	$55,477	$53,585	Aug-2019	Apr-2017	Mar-2022	26,744	3,299	6,581	9,885	3,084	-	3,084	-	-	-	-
		Aquidneck Island - Other Sub Improvements	Engineering: -50% / -25%	$1,990		Nov-2018	Nov-2021	Mar-2022	-	-	810	810	720	-	720	732	-	-	-
		Jepson Substation	Phase: Final Cutovers & Project Closeout, Estimate +/- 10%	$21,848		Oct-2018	Apr-2018	Aug-2021	17,333	994	1,936	3,310	650	-	650	-	-	-	-
		East Providence Substation	Project Development	$18,000	$18,000	Feb-2017	—	—	765	176	240	1,550	731	-	731	6,060	5,591	2,146	-
		New Lafayette Sub	Project Development Ending +/- 25%	13,300	13,300	Oct-2020	—	—	25	420	3,004	380	1,457	-	1,457	1,995	3,395	104	0
		Warren Substation	Project Development	$8,700	$8,700	—	—	—	413	127	182	485	621	-	621	1,118	1,226	2,798	1,689
		Weaver Hill Rd	Pre-Project development	—	—	—	—	—	-	-	-	-	-	-	-	-	450	800	730
		New London Expansion	Pre-Project development	—	—	—	—	—	-	-	-	-	-	-	-	-	150	820	1,523
	Major Projects Total									4,037	11,564	15,880	8,643	-	8,643	10,804	9,703	6,481	3,942
	Other	3V0								447	1,693	540	1,435	-	1,435	130	-	-	-
		Strategic DER Advancement								-	-	1,700	-	-	-	1,310	1,800	1,800	1,800
		EMS/RTU								134	351	880	1,551	(250)	1,300	1,635	1,089	1,058	208
		OH Line Transformer Replacements								294	650	650	700	-	700	710	730	730	740
		Other Load Relief & Reliability								371	1,468	385	277		279	240	250	100	100
		Storm Hardening								1	5	-	59	-	59	775	-	-	-
		VVO								623	1,184	1,135	3,227	-	3,227	3,000	3,000	3,000	3,000
		Blanket Projects - SCP								556	1,300	1,395	1,790	-	1,790	1,810	1,837	1,864	1,892
		Reserves - SCP								-	-	-	-	-	-	5,400	14,248	23,710	34,279
		GRIDMOD								-	-	-	-	-	-	27,000	27,000	32,000	33,000
	Other Total									2,627	8,781	6,755	8,979	(250)	8,729	42,370	48,724	64,862	72,819
System Capacity & Performance Total										6,653	18,344	22,645	18,622	(250)	18,372	53,194	58,426	71,423	76,761
Discretionary - Asset Condition	Major Projects	Dyer Street - Indoor Sub	Phase: Project Development, Estimate 4.3	$14,184	$14,184	Feb-2017	May-2022	Nov-2023	3,004	198	2,980	7,380	8,717	-	8,717	47	-	-	-
		South Street Completion	Phase: Final Cutovers & Project Closeout, Estimate +/- 10%	$49,269	$37,050	Jun-2018	Mar-2016	Dec-2018	32,849	31	225	-	297	-	297	-	-	-	-
		Prov PH1A-Dist Line Retire/Rebuild-Admiral/Ol	Phase: Final Design & Construction, Estimate 4.3	$11,482	$11,482	Jan-2020	Oct-2020	Nov-2023	449	337	3,849	3,800	4,988	-	4,988	1,339	-	-	-
		Prov PH1B-Construction Admiral St Substation	Project Development	—	—	—	—	—	627	339	475	1,440	3,695	-	3,695	7,960	11,271	1,183	-
		Prov PH4-Construction-Knightsville Substation	Project Development to Start FY2022	—	—	—	—	—	360	3	13	-	495	-	495	3,913	3,537	1,185	-
		Prov PH3-Substation-Ret.-Harris/[illegible]	Pre-Project development	—	—	—	—	—	-	-	-	-	-	-	-	-	-	-	-
		Prov PH3-Dist Line Retire Harris/[illegible]	Pre-Project development	—	—	—	—	—	348	3	11	-	-	-	-	1,419	8,630	10,158	7,089
	Major Projects Total									808	7,432	11,400	18,270	-	18,270	13,398	11,440	11,324	7,089
	SouthEast Substation		Phase: Final Cutovers & Project Closeout, Estimate +/- 10%	$25,440	$18,600	Jul-2018	Oct-2019	Apr-2020	6,987	4,841	11,795	10,080	2,082	-	2,082	22	-	-	-
	SouthEast Substation Total									4,841	11,795	10,080	2,082	-	2,082	22	-	-	-
	Other	Battery Replacement								170	198	220	150	-	150	130	200	250	850
		Blanket Projects - AC								1,816	3,400	3,480	3,590	-	3,590	3,694	3,747	3,799	3,865
		I&M								1,269	2,800	2,800	3,000	-	3,000	3,000	3,000	2,800	2,800
		RURD								4,247	4,942	4,700	6,000	(1,300)	4,700	6,000	6,000	6,100	6,200
		Other Asset Replacement								1,424	3,112	1,860	756	-	756	1	1	-	-
		Recloser Replacement Program								305	388	800	365	100	365	300	300	-	-
		Reserves - AB								-	1,000	1,000	-	-	-	1,860	8,600	14,186	17,200
		Substation Breakers & Reclosers								800	1,637	1,305	3,028	-	3,028	3,454	-	-	-
		UG Cable Replacements								2,136	2,756	3,600	5,500	(500)	5,000	5,500	5,500	6,000	6,000
		UG Improvements								887	1,093	979	400	-	400	400	-	-	-
	Other Total									13,218	22,464	20,540	21,721	(1,700)	20,021	24,129	23,247	32,835	36,415
Asset Condition Total										18,866	40,690	41,620	40,183	(1,700)	40,483	37,749	40,787	45,458	43,480
Discretionary - Non-Infrastructure		Corporate/Admin/General								656	5	-	-	-	-	-	-	-	-
		General Equipment								38	180	330	250	-	250	254	258	263	268
		Telecommunications								8	439	250	1,080	-	1,080	1,070	280	290	300
Non-Infrastructure Total										748	624	580	1,330	-	1,330	1,324	538	553	568
Discretionary Total										26,380	61,658	64,845	60,135	(1,950)	60,185	91,267	100,751	117,435	120,812
Non-Discretionary - Customer Requests / Public Requirements		3rd Party Attachments								(58)	87	300	181	-	181	224	228	241	248
		COVID - WORK								49	412	-	3,000	-	3,000	-	-	-	-
		Land and Land Rights								161	258	385	385	-	383	389	405	411	417
		Meter Programs								3	133	250	600	-	600	400	300	-	-
		Meters - Dist								715	2,080	2,745	2,775	-	2,775	2,617	2,659	2,802	2,848
		New Business - Commercial								3,075	8,085	8,405	9,088	-	9,088	8,877	9,087	9,258	9,450
		New Business - Residential								(734)	1,768	4,270	4,020	-	4,020	4,058	4,123	4,190	4,258
		Outdoor Lighting								563	300	319	577	-	577	535	542	551	558
		Public Requirements								(80)	3,212	2,870	2,950	-	2,950	3,045	3,074	3,103	3,133
		Transformers & Related Equipment								3,006	4,300	4,000	4,903	-	4,903	4,983	5,064	5,140	5,217
		DER - Non-Discretionary								-	2,000	2,000	5,400	(2,700)	2,700	-	-	-	-
		Distributed Generation								-	-	1,000	1,000	-	1,000	1,000	1,000	1,000	1,000
		Outdoor Lighting - Capital								-	-	-	-	-	-	-	-	-	-
Customer Request/Public Requirement Total										5,438	22,588	26,540	33,887	(2,700)	31,187	24,846	26,075	26,797	27,226
Non-Discretionary - Damage/Failure		Damage/Failure								6,728	10,935	9,740	9,539	-	9,539	9,871	9,418	9,863	10,113
		Major Storms (weather)								3,487	4,856	1,725	1,750	-	1,750	1,775	1,800	1,825	1,850
		Reserves - DF								-	484	800	820	-	820	840	860	880	1,000
Damage/Failure Total										10,215	16,275	12,265	12,109	-	12,109	12,486	12,078	12,568	12,963
Non-Discretionary Total										15,653	38,844	38,805	46,185	(2,700)	43,485	38,732	38,249	39,565	40,188
Grand Total										41,935	100,513	103,750	106,300	(4,650)	103,650	130,000	140,000	157,000	161,000

Attachment 4 – System Reliability Data

A comparison of reliability performance in calendar year (CY) 2019 relative to that of previous years is shown in the charts below. As shown below in Chart 2, the Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2019, with SAIFI of 1.02 against a target of 1.05, and SAIDI of 68.2 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days.[7]

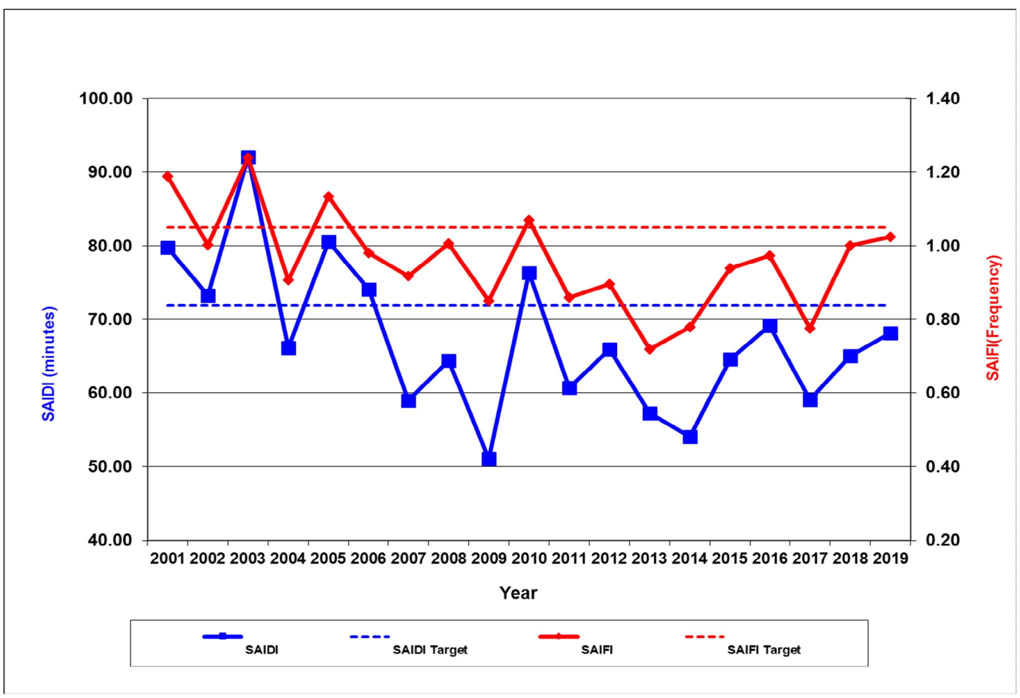
The Plan focuses on the underlying drivers of reliability during the entire year. Including major event days would skew that analysis significantly for the small number of days a year that are major event days. For example, including major event days would underestimate the day-to-day drivers of reliability due to substation or underground equipment, because, typically, overhead equipment is most impacted by major event days, which are usually weather driven events. In CY 2019, six days were characterized as major event days. The chart below provides additional details on CY 2019's major event days.

[7] A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (5.05 minutes for CY 2019). 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.

Attachment 4 - Chart 1
CY 2019 Major Event Days

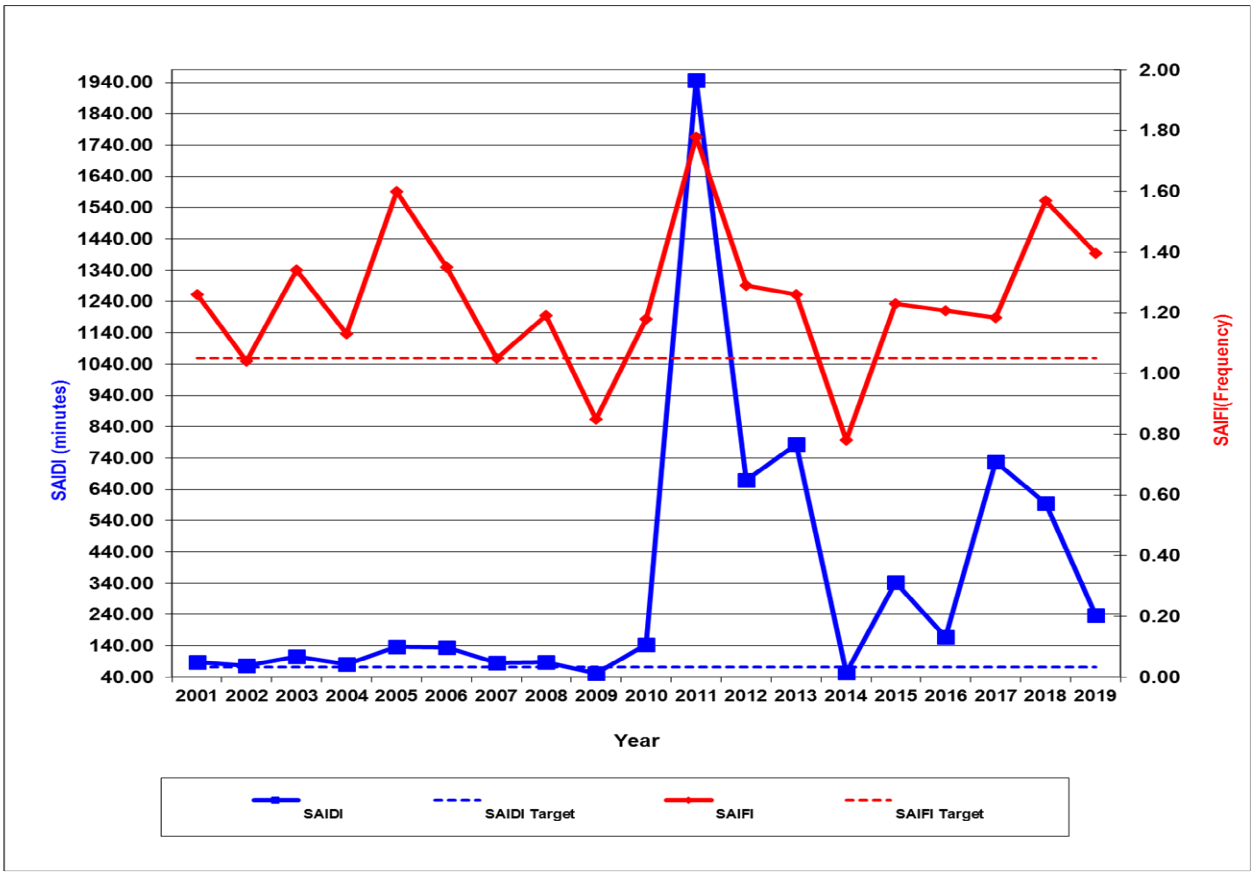
CY 2019 Major Event Days	Days Excluded	Total Customers Interrupted	Daily SAIDI
February Winter Storm	2/25/2019	36,238	10.97
April Lightnight Storm	4/15/2019	26,023	8.09
October Nor'easter	10/16/2019	15,442	33.92
October Nor'easter	10/17/2019	43,359	62.61
Wind Storm	10/31/2019	11,676	6.17
Wind Storm	11/1/2019	43,949	46.98

Attachment 4 - Chart 2
RI Reliability Performance CY 2001 – CY 2019
Regulatory Criteria (Excluding Major Event Days)



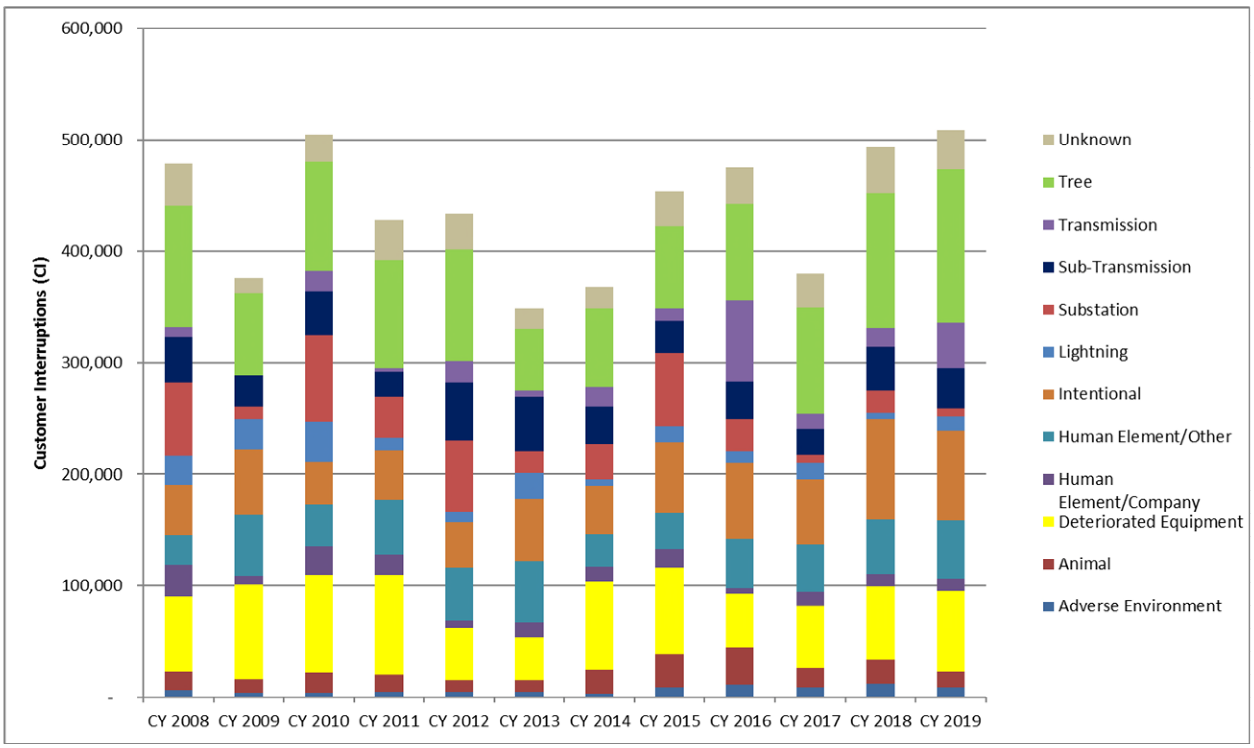
For informational purposes, Attachment 4, Chart 3 below shows reliability performance from CY 2001 to CY 2019, including major event days.

Attachment 4 - Chart 3
RI Reliability Performance CY 2001 – CY 2019
Regulatory Criteria (Including Major Event Days)



Attachment 4, Chart 4 below show the customers interrupted by cause for CY 2008 through CY 2019. Chart 5 shows the same information in tabular form.

Attachment 4 - Chart 4
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2019)

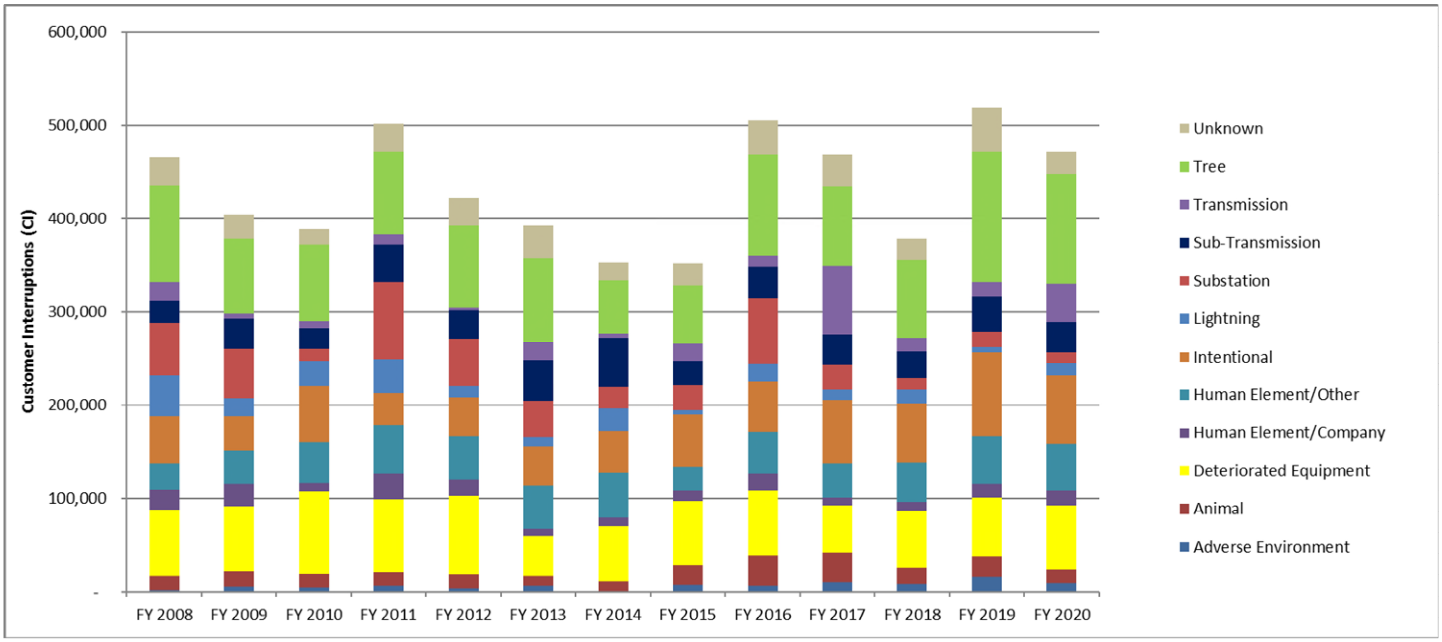


Attachment 4 - Chart 5
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2019)

Cause	CY 2008	CY 2009	CY 2010	CY 2011	CY 2012	CY 2013	CY 2014	CY 2015	CY 2016	CY 2017	CY 2018	CY 2019
Adverse Environment	5,910	3,926	3,800	4,444	4,778	4,318	3,220	8,677	10,928	8,115	11,964	8,507
Animal	16,977	11,769	18,021	15,547	9,912	10,324	21,247	29,831	33,541	18,340	21,664	14,277
Deteriorated Equipment	67,114	85,047	87,768	89,743	47,301	39,131	79,260	77,575	47,966	55,316	65,386	72,114
Human Element/ Co.	28,298	8,450	26,047	18,455	7,043	13,481	13,259	16,619	5,489	12,995	11,462	11,392
Human Element/Other	27,607	54,275	36,999	48,650	47,404	54,719	29,908	33,049	43,514	42,510	48,520	52,266
Intentional	44,887	58,356	37,743	44,526	40,927	55,927	43,132	62,373	68,273	58,544	90,092	80,218
Lightning	25,987	27,874	36,859	11,044	9,362	23,310	5,745	14,374	10,832	14,505	5,766	12,648
Substation	65,704	10,713	77,189	37,086	63,397	18,882	30,888	65,932	28,525	6,616	19,802	7,830
Sub-Transmission	40,845	28,046	40,034	22,524	51,972	48,902	33,556	29,211	33,994	23,710	39,235	35,645
Transmission	8,721	25	18,438	2,973	19,099	5,958	18,284	11,594	72,808	13,786	17,106	40,969
Tree	109,214	74,116	97,807	97,485	100,459	55,056	70,277	73,248	87,036	95,025	120,812	137,437
Unknown	37,501	13,545	23,962	36,065	32,176	19,008	19,657	31,703	32,088	30,918	41,014	35,586
Grand Total	**478,765**	**376,142**	**504,667**	**428,542**	**433,830**	**349,016**	**368,433**	**454,186**	**474,994**	**380,380**	**492,823**	**508,889**

Although service quality for the Company is based on a calendar year, the Electric ISR Plan's capital spending is reported on a fiscal year. Charts 6 and 7 provide the reliability data as presented in Charts 4 and 5 by fiscal year.

Attachment 4 - Chart 6
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2020)



Attachment 4 - Chart 7
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2020)

Cause	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020
Adverse Environment	1,673	5,651	4,018	5,992	3,674	6,584	811	6,786	5,922	10,108	8,576	15,164	9,390
Animal	15,103	16,303	14,751	15,335	15,008	9,864	10,098	21,232	32,266	31,931	17,356	22,034	14,539
Deteriorated Equipment	71,336	69,296	88,655	78,009	84,052	43,196	59,239	68,992	69,921	50,930	60,685	63,578	68,506
Human Element / Co.	20,633	24,393	8,846	27,305	17,722	8,500	9,304	11,507	17,943	8,266	9,641	14,443	15,851
Human Element / Other	28,547	35,531	44,248	51,837	46,171	45,152	48,008	25,659	45,280	36,344	42,597	51,756	50,234
Intentional	50,735	36,569	59,581	33,987	41,879	42,989	44,451	55,268	54,661	67,444	62,978	89,138	73,589
Lightning	44,176	19,577	27,874	36,883	11,098	9,362	23,882	5,234	17,639	11,044	14,313	5,736	12,922
Substation	55,282	53,391	12,120	82,926	51,866	38,492	23,243	26,527	71,115	26,558	13,015	16,685	11,580
Sub-Transmission	24,298	31,628	22,243	39,770	29,805	44,084	53,550	26,191	33,727	33,741	28,224	37,180	32,350
Transmission	20,176	6,000	7,093	11,370	2,973	19,099	4,568	18,284	11,594	72,808	14,777	16,115	40,969
Tree	104,023	79,977	83,311	88,714	88,474	90,726	56,964	63,009	109,023	85,147	83,471	139,454	117,480
Unknown	29,583	26,146	15,807	29,629	29,163	34,143	18,501	23,529	35,829	34,689	23,395	47,391	25,088
Grand Total	**465,565**	**404,462**	**388,547**	**501,757**	**421,885**	**392,191**	**352,619**	**352,218**	**504,920**	**469,010**	**379,028**	**518,674**	**472,498**

Trees, Intentional, and Deteriorated Equipment were the top three drivers affecting customers, accounting for 55 percent of all interruptions in FY 2020. It is, therefore, critical that the Company continue to invest in its infrastructure and vegetation management programs to provide reliable electric delivery service to customers.

FY2022 New Projects

New Dyer St Substation Project

GOALS FOR "NEW" ELECTRIC SYSTEM	IMPACT	EXPLANATION
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances	The Company's New Dyer St substation project plans to address the asset condition issues at the existing Dyer St substation.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances	The Company's Dyer St substation project is aligned with the basis for a modern grid. The new substation will be built with all the modern functionalities e.g. EMS/RTU systems, advanced communication capabilities, and 3V0 protective equipment.
Address the challenge of climate change and other forms of pollution	Neutral	The New Dyer St station will replace the existing Dyer St substation but will not create greater capacity to interconnect renewable power resources.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Neutral	This is an asset condition project and there are no changes to system capabilities that facilitate customer investments.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	This project does not change the compensation distributed energy resources receive.
Appropriately charge customers for the cost they impose on the grid.	Neutral	This category applies to rate design and tariffs. This project does not change the analysis or guidelines that determine the customer costs for their impacts to the grid.
Appropriately compensate the distribution utility for the services it provides	Advances	This project is included in the yearly ISR Plan filing in order to recover the costs of this project is in direct alignment with this goal.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Neutral	This project is aligned with distribution utility objectives proposed under the current regulatory framework and does not change rate design, cost recovery or incentives.

Docket 4600 Benefit-Cost Framework

Project Name: New Dyer St Substation
Area Study: Providence Area Study

Problem: A condition assessment was performed on the existing Dyer St substation in 2011 as part of the Providence area study. After a review of test records and operating history, the study concluded that operation and maintenance of the existing station equipment presented challenges. The main equipment families in this station (breakers, reactors, regulators, switches, relay schemes) are deficient in the areas of performance/maintenance costs when compared to contemporary substation equipment. This station also has design aspects that make it a challenging environment to perform operations and maintenance in. The study identified the main issue to be asset condition and recommended replacement of the 4.16kV & 11kV indoor substation.

Preferred Plan: The recommended plan is to build a new 11.5kV-4.16kV substation within the South St substation outdoor yard. The substation site will consist of two 11.5kV-4.16kV transformers and one 4.16kV metalclad switchgear with 8 feeder positions. This plan also includes rehabilitation of the historically significant DC / warehouse building as required by the City of Providence, removal of all retired 4 kV and 11 kV equipment and cable from the Dyer St indoor substation and yard, and demolition of the Dyer St Indoor Substation building.

Alternate Plan: The alternate plan is to restore the currently vacant DC / warehouse building on the southwest corner of the existing National Grid Dyer St site and build a new 11 kV to 4.16 kV indoor distribution substation within the restored DC building. Retire the existing circa 1925 Dyer St Indoor Substation at the southeast corner of the site.

Summary of Benefit - Cost Analysis

Preferred Plan
Benefit Cost Ratio 0.00
Net Benefit/Cost $ (25,175,150.43)

Alternate Plan
Benefit Cost Ratio 0.00
Net Benefit/Cost $ (50,217,725.00)

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Project Name: **Dyer Street Substation - Preferred Plan**
Area Study **Legacy Study - Providence Long-term Study (2015)**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Power System	Distribution capacity costs	Applicable/Quantifiable	$ (25,262,828.09)	Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Power System	Distribution delivery costs	Not Applicable	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	Applicable/Quantifiable	$ -	Transmission Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition driven project does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This asset condition driven project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 35,251.76	Recommended plan has an estimated line loss savings of 30kW and an energy savings of approximately 54,662kWh/year compared to the existing substation and the alternative plan.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This asset condition driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This asset condition driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Not Applicable	$ 22,293.28	Recommended plan has an estimated line loss savings of 30kW and an energy savings of approximately 54,662kWh/year compared to the existing substation and the alternative plan.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This asset condition driven program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This asset condition driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This asset condition driven project does not impact transmission costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	Not Applicable	$ -	This asset condition driven project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	This asset condition project does not impact DRIPE.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This asset condition project is not categorized as an investment under uncertainty.

Project Name: **Dyer Street Substation - Preferred Plan**
Area Study **Legacy Study - Providence Long-term Study (2015)**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Not Applicable	$ 4,088.39	While this project decreases losses, it does not directly impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	Not Applicable	$ 3,677.76	While this project decreases losses, it does not directly impact GHG Compliance Costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This asset condition driven project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This asset condition driven project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	Not Applicable	$ -	This asset condition driven project does not impact Distribution system safety.
Benefit	Power System	Distribution system performance	Applicable/Quantifiable	$ -	There are no distribution system performance benefits from this asset condition driven project.
Benefit	Power System	Utility low income	Not Applicable	$ -	This asset condition driven project does not impact low income participant non-energy benefits.
Benefit	4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.	Distribution system and customer reliability / resilience impacts	Applicable/ Not Quantifiable	$ -	There are no resiliancy improvements involved in this asset condition driven project.
Benefit	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition driven project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This asset condition driven project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This asset condition driven project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This asset condition driven project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 18,660.90	GHG savings are associated with loss reductions from this project and avoided bulk energy purchases.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 685.16	Criteria air pollutant and other environmental externalist costs are associated with loss reductions from this proejct and avoided bulk energy purchases.
Benefit	Societal	Conservation and community benefits	Not Applicable	$ -	This asset condition driven project does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This asset condition driven project does not directly impact economic development.

Project Name: Dyer Street Substation - Preferred Plan
Area Study Legacy Study - Providence Long-term Study (2015)

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This asset condition driven project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This asset condition project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	Applicable/Quantifiable	$ 3,020.42	Public Health benefits are associated with emissions reductions through loss reductions from this project and avoided bulk energy purchases.
Benefit	Societal	National Security and US international influence	Not Applicable	$ -	This asset condition project does not impact National Security.

Project Name: **Dyer Street Substation - Alternate Plan**
Area Study **Legacy Study - Providence Long-term Study (2015)**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Power System	Distribution capacity costs	Applicable/Quantifiable	$ (50,217,725.00)	Distribution Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Power System	Distribution delivery costs	Not Applicable	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	Applicable/Quantifiable	$ -	Transmission Project costs (C, R, OM) and yearly expense to operate and maintain the project equipment.
Cost	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition driven project does not impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This asset condition project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ -	There are no avoided Bulk energy purchases benefits from this asset condition driven project.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This asset condition driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This asset condition driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Not Applicable	$ -	This asset condition driven project does not impact energy costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This asset condition driven program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This asset condition driven project does not impact generation capacity or REC costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This asset condition driven project does not impact transmission costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	Not Applicable	$ -	This asset condition driven project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	This asset condition project does not impact DRIPE.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This asset condition project is not categorized as an investment under uncertainty.

Project Name: Dyer Street Substation - Alternate Plan
Area Study Legacy Study - Providence Long-term Study (2015)

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Not Applicable	$ -	This asset condition project does not impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	Not Applicable	$ -	This asset condition driven project does not impact GHG Compliance Costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This asset condition driven project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This asset condition driven project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	Not Applicable	$ -	This asset condition driven project does not impact Distribution system safety.
Benefit	Power System	Distribution system performance	Applicable/Quantifiable	$ -	There are no distribution system performance benefits from this asset condition driven project.
Benefit	Power System	Utility low income	Not Applicable	$ -	This asset condition driven project does not impact low income participant non-energy benefits.
Benefit	4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.	Distribution system and customer reliability / resilience impacts	Applicable/ Not Quantifiable	$ -	The regular development of the construction and equipment standards applied in execution of projects that result in expansion and/or modification of distribution infrastructure support specific areas in which system resiliency/hardening is a focus.
Benefit	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition driven project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This asset condition driven project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This asset condition driven project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This asset condition driven project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ -	There are no Greenhouse gas externality cost benefits from this asset condition driven project.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ -	There are no air pollutant or other environmental externality cost benfits from this asset condition project.
Benefit	Societal	Conservation and community benefits	Not Applicable	$ -	This asset condition driven project does not directly reduce Environmental Impacts.
Benefit	Societal	Non-energy costs/benefits: Economic Development	Applicable/Not Quantifiable	$ -	This asset condition driven project does not directly impact economic development.

Project Name: **Dyer Street Substation - Alternate Plan**
Area Study **Legacy Study - Providence Long-term Study (2015)**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This asset condition drivene project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This asset condition project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	Applicable/Quantifiable	$ -	This asset confidition project does not impact Public Health.
Benefit	Societal	National Security and US international influence	Not Applicable	$ -	This asset condition/system performance project does not impact National Security.

VVO Projects (Farnum Pike, Pontiac and Putnam Pike)

GOALS FOR "NEW" ELECTRIC SYSTEM	IMPACT	EXPLANATION
Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels)	Advances	The Company's VVO projects will benefit customers by reducing customer demand and energy use and improve affordability of the electric system.
Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures	Advances	The Company's VVO projects will benefit customers by reducing customer demand and energy usage through optimization of the electric system with advanced devices.
Address the challenge of climate change and other forms of pollution	Advances	The reduction of energy usage resulting from these projects could reduce emissions of fossil fuel generators.
Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits	Neutral	This plan does not detract from or facilitate a customer's investment in their facilities.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	The Company's VVO projects do not change the compensation distributed energy resources receive.
Appropriately charge customers for the cost they impose on the grid	Neutral	This category applies to rate design and tariffs. The Company's infrastructure programs do not change the analysis or guidelines that determine the customer costs for their impacts to the grid.
Appropriately compensate the distribution utility for the services it provides	Advances	The Company's VVO projects are included in the yearly ISR Plan filing in order to recover the costs of the work and is in direct alignment with this goal.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances	The Company's VVO projects facilitate the alignment of distribution utility, customer, and policy objectives and interests.

Docket 4600 Benefit-Cost Framework

Project Name: VVO Farnum Pike Substation
Area Study: Program

Problem: The intent of this project is to flatten and lower the feeder voltage profile through the use of additional voltage monitors along the feeder and centralize control of the regulating devices to provide customer energy savings and lower electric bills.

Preferred Plan: The Farnum Substation circuits (6) have been selected for the next installation of volt-var optimization functionality. The circuits and substation have suitable load levels, customer counts, and existing substation automation resulting in a cost effective likelihood of customer energy savings as shown by the benefit-cost ratio below.

Alternate Plan: N/A

Summary of Benefit - Cost Analysis

Preferred Plan

Benefit Cost Ratio 2.67
Net Benefit/Cost $ 3,793,864.75

Alternate Plan

Benefit Cost Ratio N/A
Net Benefit/Cost N/A

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. Transmission costs are currently calculated on a regional basis. The analysis will be refined to prorate the cost on a Rhode Island specific basis.

3. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

4. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

5. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

6. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Project Name: **VVO Farnum Pike Substation**
Area Study: **Program**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Power System	Distribution capacity costs	Applicable/Quantifiable	$ (2,270,135.19)	Distribution Project costs (C, R, OM) and yearly expense to operate a maintain the project equipment.
Cost	Power System	Distribution delivery costs	Not Applicable	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	Not Applicable	$ -	This project does not have associated Transmission project costs.
Cost	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not have non-energy costs that impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 2,931,394.86	This benefit is the value of avoided energy across the six feeders served by the Farnum substation.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This project does not directly impact generation capacity or REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Applicable/Quantifiable	$ 792,172.47	This project has a peak capacity reduction effect.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This project does not directly impact generation capacity or impact REC costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This project does not impact transmission costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	Not Applicable	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	This project does not directly impact option values of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This project is not categorized as an investment under uncertainty.

Project Name: VVO Farnum Pike Substation
Area Study: Program

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Applicable/Quantifiable	$ 165,791.09	This project has an energy and capacity DRIPE effect.
Benefit	Power System	Greenhouse gas compliance costs	Applicable/Quantifiable	$ 307,085.85	This project results in a greenhouse gas compliance benefit associated with the energy reduction.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system safety.
Benefit	Power System	Distribution system performance	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system voltage performance.
Benefit	Power System	Utility low income	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	Not Applicable	$ -	This project does not impact customer reliability or resilience.
Benefit	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 1,558,147.43	This project results in a greenhouse gas externality benefit associated with the energy reduction.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 57,209.32	This project results in air pollutant externality benefit associated with the energy reduction.
Benefit	Societal	Conservation and community benefits	Not Applicable	$ -	This project does not impact conservation and community benefits.
Benefit	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not directly impact economic development.

Project Name: **VVO Farnum Pike Substation**
Area Study: **Program**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	Applicable/Quantifiable	$ 252,198.93	This project results in a societal public health benefit associated with the emissions reductions.
Benefit	Societal	National Security and US international influence	Not Applicable	$ -	This project does not impact National Security.

Docket 4600 Benefit-Cost Framework

Project Name: VVO Putnam Pike Substation
Area Study: Program

Problem: The intent of this project is to flatten and lower the feeder voltage profile through the use of additional voltage monitors along the feeder and centralize control of the regulating devices to provide customer energy savings and lower electric bills.

Preferred Plan: The Putnam Pike Substation circuits (3) have been selected for the next installation of volt-var optimization functionality. The circuits and substation have suitable load levels, customer counts, and existing substation automation resulting in a cost effective likihood of customer energy savings as shown by the benefit-cost ratio below.

Alternate Plan: N/A

Summary of Benefit - Cost Analysis

Preferred Plan
Benefit Cost Ratio 1.61
Net Benefit/Cost $ 2,427,088.18

Alternate Plan
Benefit Cost Ratio N/A
Net Benefit/Cost N/A

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. Transmission costs are currently calculated on a regional basis. The analysis will be refined to prorate the cost on a Rhode Island specific basis.

3. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

4. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

5. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

6. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Project Name: **VVO Putnam Pike Substation**
Area Study: **Program**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Power System	Distribution capacity costs	Applicable/Quantifiable	$ (4,007,357.05)	Distribution Project costs (C, R, OM) and yearly expense to operate a maintain the project equipment.
Cost	Power System	Distribution delivery costs	Not Applicable	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	Not Applicable	$ -	This project does not have associated Transmission project costs.
Cost	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not have non-energy costs that impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 3,096,400.11	This benefit is the value of avoided energy across the three feeders served by the Putnam Pike substation.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This project does not directly impact generation capacity or REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Applicable/Quantifiable	$ 836,763.05	This project has a peak capacity reduction effect.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This project does not directly impact generation capacity or impact REC costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This project does not impact transmission costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	Not Applicable	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	This project does not directly impact option values of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This project is not categorized as an investment under uncertainty.

Project Name: VVO Putnam Pike Substation
Area Study: Program

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Applicable/Quantifiable	$ 175,123.30	This project has an energy and capacity DRIPE effect.
Benefit	Power System	Greenhouse gas compliance costs	Applicable/Quantifiable	$ 324,512.50	This project results in a greenhouse gas compliance benefit associated with the energy reduction.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system safety.
Benefit	Power System	Distribution system performance	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system voltage performance.
Benefit	Power System	Utility low income	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	Not Applicable	$ -	This project does not impact customer reliability or resilience.
Benefit	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 1,674,679.58	This project results in a greenhouse gas externality benefit associated with the energy reduction.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 60,455.86	This project results in air pollutant externality benefit associated with the energy reduction.
Benefit	Societal	Conservation and community benefits	Not Applicable	$ -	This project does not impact conservation and community benefits.
Benefit	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not directly impact economic development.

Project Name: **VVO Putnam Pike Substation**
Area Study: **Program**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	Applicable/Quantifiable	$ 266,510.83	This project results in a societal public health benefit associated with the emissions reductions.
Benefit	Societal	National Security and US international influence	Not Applicable	$ -	This project does not impact National Security.

Docket 4600 Benefit-Cost Framework

Project Name:	VVO Pontiac Substation
Area Study:	Program
Problem:	The intent of this project is to flatten and lower the feeder voltage profile through the use of additional voltage monitors along the feeder and centralize control of the regulating devices to provide customer energy savings and lower electric bills.
Preferred Plan:	The Pontiac Substation circuits (6) have been selected for the next installation of volt-var optimization functionality. The circuits and substation have suitable load levels, customer counts, and existing substation automation resulting in a cost effective likihood of customer energy savings as shown by the benefit-cost ratio below.
Alternate Plan:	N/A

Summary of Benefit - Cost Analysis

Preferred Plan

Benefit Cost Ratio	3.22
Net Benefit/Cost	$ 4,003,310.27

Alternate Plan

Benefit Cost Ratio	N/A
Net Benefit/Cost	N/A

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. Transmission costs are currently calculated on a regional basis. The analysis will be refined to prorate the cost on a Rhode Island specific basis.

3. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

4. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

5. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

6. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

Project Name: **VVO Pontiac Substation**
Area Study: **Program**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Power System	Distribution capacity costs	Applicable/Quantifiable	$ (1,804,424.68)	Distribution Project costs (C, R, OM) and yearly expense to operate a maintain the project equipment.
Cost	Power System	Distribution delivery costs	Not Applicable	$ -	Cost to operate and maintain the project equipment is included in the line item above.
Cost	Power System	Electric transmission infrastructure costs for Site Specific Resources	Not Applicable	$ -	This program does not have associated Transmission project costs.
Cost	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not have non-energy costs that impact water or other fuels.
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 2,803,464.91	This benefit is the value of avoided energy across the six feeders served by the Pontiac substation.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This project does not directly impact generation capacity or REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Not Applicable	$ 757,601.01	This project has a peak capacity reduction effect.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This program does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This project does not directly impact generation capacity or impact REC costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This project does not impact transmission costs.
Benefit	Power System	Net risk benefits to utility system operations (generation, transmission, distribution) from 1) Ability of flexible resources to adapt, and 2) Resource diversity that limits impacts, taking into account that DER need to be studied to determine if they reduce or increase utility system risk based on their locational, resource, and performance diversity	Not Applicable	$ -	This project does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	This project does not directly impact option values of individual resources.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This project is not categorized as an investment under uncertainty.

Project Name: VVO Pontiac Substation
Area Study: Program

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Not Applicable	$ 158,555.74	This project has an energy and capacity DRIPE effect.
Benefit	Power System	Greenhouse gas compliance costs	Not Applicable	$ 294,867.01	This project results in a greenhouse gas compliance benefit associated with the energy reduction.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This project does not impact innovation or market transformation or provide innovation and learning by doing.
Benefit	Power System	Distribution system safety loss/gain	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system safety.
Benefit	Power System	Distribution system performance	Applicable - See Qualification	Applicable - See Qualification	Although the primary purpose of this project is energy savings, the advanced capacitors provide an increased level of voltage control improving system voltage performance.
Benefit	Power System	Utility low income	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	Applicable - See Qualification	$ -	This project does not impact customer reliability or resilience.
Benefit	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this project.
Benefit	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This project does not impact water or other fuels.
Benefit	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This project does not directly impact customer empowerment.
Benefit	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This project does not directly impact customer rate and bills.
Benefit	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 1,496,149.27	This project results in a greenhouse gas externality benefit associated with the energy reduction.
Benefit	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 54,932.98	This project results in air pollutant externality benefit associated with the energy reduction.
Benefit	Societal	Conservation and community benefits	Not Applicable	$ -	This project does not impact conservation and community benefits.
Benefit	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This project does not directly impact economic development.

Project Name: **VVO Pontiac Substation**
Area Study: **Program**

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This project does not impact innovation or market transformation.
Benefit	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This project does not impact low income participant non-energy benefits.
Benefit	Societal	Public Health	Applicable/Quantifiable	$ 242,164.02	This project results in a societal public health benefit associated with the emissions reductions.
Benefit	Societal	National Security and US international influence	Not Applicable	$ -	This project does not impact National Security.

Section 3
Vegetation Management

Section 3

Vegetation Management Plan
FY 2022 Electric ISR Plan

Section 3: Vegetation Management (VM)

The Company's VM Program is an essential component of the Company's plan to maintain the safety and reliability of its electric distribution network. Trees are an important concern for several reasons. Tree contact with the electric distribution system increases the risk of electric shock to the public, slows the restoration of critical infrastructure, and may increase the risk of fire. Trees can also have a significant impact on reliability. Tree contact with the distribution system during windy/stormy conditions may cause a phase-to-phase fault, which will trip either a line fuse, pole recloser, or a station breaker causing an interruption in service.

As shown in Section 2, Attachment 4, Chart 7, trees were responsible for approximately 117,480 customers interrupted in FY 2020, which represented 25 percent of the total interruptions. Trees were the leading cause of customer interruptions during FY 2020.

The Company has developed a strong VM program, which provides a measure of safety for the public/workforce, favorable operational efficiency, and minimizes the number of customer interruptions due to trees. The Company's VM program includes several different activities, each addressing a different aspect of utility vegetation management.

Cycle Pruning

The cycle pruning program is designed to ensure that the vegetation growth along the overhead portion of the Company's distribution network does not interfere with the safe and reliable performance of the electric network. Cycle Pruning includes the scheduling of every distribution circuit for pruning on a fixed timeframe or rotation. The pruning work performed is based on a dimension clearance specification. Cycle Pruning is designed to maintain an acceptable clearance between overhead conductors and vegetation to minimize the safety risk to the public and utility workforce. A stable and consistently funded circuit pruning program minimizes the risks of public and worker electrocution as well as wild fire events and is a utility best practice[8].

Consistent circuit pruning also helps maintain service reliability and supports efficient management of the overhead network. Managing the vegetation along the network helps to avoid interruptions caused by phase-to-phase tree contact and makes the network more accessible to line crews so they can restore power quickly following an interruption. Cycle pruning also provides crews the clearance necessary to accurately inspect circuits and to more efficiently perform any required maintenance which also helps avoid interruptions. A review of the cycle pruning program from FY 2007 to FY 2020 shows, on average, a 11 percent improvement in customer interruptions per circuit in the first year after pruning.

The Company continues to recommend a four-year pruning cycle for the Rhode Island overhead distribution assets based on tree growth rates and the acceptable clearance dimensions obtained at the time of pruning. The total overhead distribution mileage in Rhode Island is approximately 5,116 miles. To maintain a four-year pruning cycle, an average of 1,279 miles, need to be pruned each year. After detailed field analysis of the current circuits due at this time,

[8] Best Management Practices, Utility Pruning of Trees; Special companion publication to the ANSI A300 Part 1: Tree, Shrub, and Other Woody Plant Maintenance-Standard Practices (Pruning)

the FY 2022 plan will require the pruning of 1,388 miles of distribution. The estimated cost for distribution cycle pruning in FY 2022 is $6.6 million.

Enhanced Hazard Tree Mitigation (EHTM)

Hazard tree removal, as part of a complete utility vegetation management program, is also a utility best practice. Full tree and large limb failures have been shown to account for a significant portion of customer interruptions, not only in Rhode Island but also in other states. Using three years of tree-related interruption data for Rhode Island indicates that fallen trees account for 48 percent of tree-related events and 62 percent of tree-related customer interruptions.

To address this issue, in 2008, the Company implemented the EHTM program to identify and remove dying or structurally weakened trees and overhanging leads along the three phase sections of distribution circuits. The three-phase portion of the circuit is the most susceptible to tree caused faults and serves the highest number of customers. Therefore, hazard tree removal on three-phase sections of the distribution circuit intuitively provides the highest benefit per hazard tree removal dollar. EHTM uses an industry leading tree risk assessment protocol to identify hazard trees.

The purpose of the EHTM program is primarily to provide a reliability benefit. The program targets the mainline three-phase portion of the Company's worst performing circuits where tree caused phase-to-phase faults will interrupt the entire population of customers on that circuit. To demonstrate these benefits and to meet the requirements of the FY 2012 Rhode

Island Electric ISR Plan,[9] a study of the Company's EHTM program was performed. From FY 2008 to FY 2020, the results show an average improvement of tree-related Customers Interruptions (CI) by circuit of 69 percent for the first year following project completion, which demonstrates a significant improvement in customer service reliability on targeted circuits.

At the Open Meeting on March 20, 2018 in Docket No. 4783, the Commission directed the Company to include a summary in its FY 2019 ISR quarterly reports of the Gypsy Moth and other pest-related damage tracked by the Company. The Company has been successful dealing with the Gypsy Moth infestation over the last few years, removing thousands of trees and avoiding a significant increase in tree-related outages. Over the next few years, the Company will need to continue these efforts to address the Emerald Ash Borer infestation throughout the State of Rhode Island. These challenges require the Company to coordinate with numerous state and municipal entities to maintain an acceptable level of reliability for our customers in the State of Rhode Island. To continue to be proactive with identifying and removing hazard trees, the Company is proposing an EHTM budget of $1.5 million in FY 2022.

[9] Electric ISR Plan Vegetation Management Cost Benefit Report, filed September 5, 2012.

Sub-Transmission

This category includes VM activities for the sub-transmission (Sub-T) right-of-way network. Much like distribution cycle pruning, the Sub-T circuits are treated on a four-year cycle, but because of the smaller population, these circuits are not as easily balanced year-to-year. The total cost for the required FY 2022 Sub-T VM work is $0.5 million. Currently, the Company has 107 miles of sideline work scheduled for FY 2022.

Police Detail/Flagman

To safely perform the Cycle Pruning and EHTM, the Company is required to hire police details and flagman. For FY 2022, police detail costs are estimated to be $775,000. The Company considers several factors when estimating the police detail budget, including but not limited to, prior years' costs per mile and percent of total budget, as well as the general police detail policies of the specific towns and municipalities where work is to be performed during the fiscal year. Police detail and flagging costs have remained relatively stable for the last few years. These costs remain well below similar police detail costs in Massachusetts, which also requires the use of police details. Historically, police detail costs in Massachusetts have ranged from 15 percent to 20 percent of total vegetation management costs. By contrast, in Rhode Island, from FY 2012 through FY 2020, police detail costs represented five percent to nine percent of total vegetation management costs. Police and flagging costs are projected to be seven percent for FY 2022.

Importantly, police detail and flagger costs are driven primarily by factors outside of the Company's control, including a myriad of municipal requirements, work locations, and the hourly rates set by the municipalities. For example, the number and levels or required details vary by town and by traffic and road conditions. Also, certain towns mandate the use of police officers on a detail and limit or restrict the use of less expensive third-party flaggers. Depending on the town, different factors such as municipal ordinances, requirements in police union contracts or specific safety municipal requirements can play of role in the ability of the Company to manage its total police detail costs budget.

Notwithstanding these factors, the Company has adopted changes to attempt to minimize police detail and flagger costs where possible. This includes removing police detail costs from the Company's Cycle Pruning program vendor bidding process and placing these costs into a separate police detail and flagger budget account. This permits the Company to separately track detail costs and provides a more accurate historical basis for discussions with municipalities designed to mitigate police and detail costs, where possible. In addition, the VM program police protection processes are coordinated with the Company's electric and gas construction departments. The VM program police protection processes are also coordinated with the Company's community relations department so that the Company can discuss police detail requirements with communities and municipalities in advance of performing the work.

Additionally, since the Company's tree pruning work is performed by contractors, the Company has added police detail costs to the system used to evaluate overall contractor performance for a fiscal year, thus creating an incentive for contractors to actively focus on police details. To assist with this effort, the Company has also revised its contracting strategies by placing only one contractor in each municipality during a given year. This allows each contractor to develop a relationship with each town, and to better address communications with public safety officials.

Core Activities

The Company performs other essential VM activities to efficiently maintain the safety and reliability of the network and to address customer needs. In contrast with Cycle Pruning and EHTM, the Company has very little discretion over the timing of these activities. This work includes responding to customer requests for vegetation-related work due to safety and reliability concerns. It also includes response to requests for interim or spot trimming by circuit patrols in locations where vegetation growth has exceeded normal conditions or where the patrols have identified other vegetation-related reliability concerns. Responding to sporadic emergency calls to remove trees or limbs from wires and to perform vegetation work necessary to restore power to customers is another important core activity performed by forestry crews. Spending for each core activity varies from year-to-year depending on customer calls, weather, and system requirements. Each core activity separately consumes a small and variable proportion of the overall budget. For FY 2022, the Company expects to spend $1.2 million for the core activities.

In FY 2022, the Company projects a continuation of the $0.2 million to focus on pockets of poor performance. These are areas where customers are experiencing a large number of tree-related outages which the Company's routine pruning and EHTM programs have not been able to address. The Company would like to take a more prescriptive approach and focus on trees outside our normal scope of work. The Company will track tree-related reliability in these areas to determine the effectiveness of the program and evaluate whether or not the program should continue and/or possibly be expanded in the future.

Fiscal Year 2022 Vegetation Management Budget

As detailed in Chart 1 below, the FY 2022 Electric ISR Plan proposes to spend approximately $10.8 million for VM. This represents a 2 percent increase from the $10.6 million which was approved for FY 2021.

Section 3 – Chart 1
Vegetation Management Spending
($000)

Category	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	Proposed FY 2022
Cycle Prune (Base)	$4,475	$5,414	$5,050	$5,500	$6,150	$5,600	$6,100	$6,600
Hazard Tree – EHTM	$1,000	$1,000	$950	$1,250	$1,250	$2,250	$1,750	$1,500
Sub-T (off & on road)	$316	$220	$780	$650	$325	$500	$550	$500
Police/Flagman Detail	$650	$750	$714	$775	$850	$825	$775	$775
Pockets of Poor Performance (New in FY21)	-	-	-	-	-	-	$200	$200
Core Crew incl. Interim/Spot Trim, Customer Requests, Emergency Response, Worst Feeders, etc.	$1,285	$1,500	$1,225	$1,225	$1,225	$1,225	$1,225	$1,225
Total	**$7,726**	**$8,884**	**$8,719**	**$9,400**	**$9,800**	**$10,400**	**$10,600**	**$10,800**

Attachment 1 Vegetation Management Cost-Benefit Analysis

Introduction and Summary

In the Rhode Island Public Utilities Commission's (Commission) Report and Order issued on May 3, 2012 on the Company's FY 2013 Electric ISR Plan, which was approved by the Commission effective March 29, 2012 pursuant to an Open Meeting decision, the Commission directed the Company to collaborate with the Division to develop a method by which the costs and benefits of the Vegetation Management Program and Inspection and Maintenance Program be tracked and reported in future ISR filings.[10]

National Grid met with the Division and its consultant, Mr. Gregory Booth on June 15, 2012 to collaboratively develop a method for the tracking and reporting of costs and benefits for both the Vegetation Management Program and Inspection and Maintenance Program. The description and method for each of these programs was filed with the Commission on June 29, 2012.[11] With respect to the Vegetation Management Program, the Company agreed to:

1. Quantify the reliability benefits for both the Enhanced Hazard Tree Mitigation (EHTM) and the Cycle Pruning Programs on a fiscal year basis with the benefits determined by comparing a pre-project three-year average to a post-project tree related number of customers interrupted and the costs calculated by a cost per feeder to calculate an overall cost per change in customer interruptions; and

[10] Docket No. 4307, Report and Order, page 16.
[11] Docket No. 4307 compliance filing of June 29, 2012, page 1.

2. Perform a Damage Restoration Cost Benefit analysis for the EHTM Program circuits using a similar method and estimate the costs of restoration.

The first Vegetation Management Program cost-benefit analyses were filed with the Commission on September 5, 2012. This constitutes the eighth filing and includes work performed in FY 2019. As set forth below, the Company provides results of the FY 2019 Reliability Cost-Benefit for the EHTM and Cycle Pruning Programs and the results of the Damage Restoration Cost-Benefit for the EHTM Program.

FY 2019 Reliability Cost-Benefit for the EHTM and Cycle Pruning Programs

To meet the requirements of the FY 2012 Electric ISR Plan, the following study of the Company's Vegetation Management Program has been performed annually since FY 2012. The analysis was done for the work performed in FY 2008 through FY 2019 for the Enhanced Hazard Tree Mitigation (EHTM) Program and FY 2007 through FY 2019 for the Cycle Pruning Program. To calculate the reliability benefits of the EHTM and Cycle Pruning Programs, the Company used the average number of tree-related customer interruptions (CI's) over a three-year period prior to the project year as the baseline. The project year was excluded from the analysis as both the EHTM Program and the Cycle Pruning Program often take most of the fiscal year to complete. Tree-related CI's were then calculated for the first full year post project completion, and for the following two years thereafter. The Company then calculated the difference between the pre-project average tree-related CI's and the post-project average tree-related CI's by calculating the percent improvement for each individual circuit in the annual work plan, and by calculating a running average percent improvement for all circuits completed under the EHTM Program. The table below is a summary of the reliability results for the EHTM Program.

Section 3 – Chart 2

EHTM Project Year	Average Annual CI Pre-Project	CI - First Year Post-Project	% Improved	CI - Second Year Post-Project	% Improved	CI - Third Year Post-Project	% Improved
2008	22,127	12,513	43%	7,477	66%	9,213	58%
2009	32,092	6,548	80%	9,013	72%	15,972	50%
2010	50,145	6,731	87%	13,032	74%	12,247	76%
2011	1,133	186	84%	425	62%	202	82%
2012	8,601	2,972	65%	522	94%	1,859	78%
2013	15,109	3,816	75%	4,647	69%	5,159	66%
2014	13,048	628	95%	9,788	25%	2,807	78%
2015	10,902	12,798	-17%	15,745	-44%	10,832	1%
2016	4,060	775	81%	279	93%	505	88%
2017	8,861	3,194	64%	11,030	-24%	7,290	18%
2018	8,573	5,475	36%	2,395	72%	-	-
2019	8,549	2,008	77%	-	-	-	-
Totals	**183,201**	**57,644**	**69%**	**74,353**	**57%**	**66,086**	**60%**

* Negative numbers represent an increase from established baseline value.

Since the beginning of the EHTM Program in FY 2008, there has been an average tree-related CI improvement of 69% in the first year, 57% in the second year, and 60% in the third year following project completion.

While the primary goal of the EHTM Program is to improve reliability, the Cycle Pruning Program provides benefits to the Company and its customers by maintaining and improving both public and worker safety. Furthermore, the Cycle Pruning Program increases the efficiency of the Company's line maintenance crews and increases the efficiency and accuracy of the Company's line inspectors. However, since the intermittent contact of branches against overhead distribution wires due to vegetation growth does not specifically cause service interruptions, the clearance of those branches through the Cycle Pruning Program will not necessarily show a significant and consistent improvement in reliability.

The table below is a summary of the reliability results for the Cycle Pruning Program.

Section 3 – Chart 3
Cycle Pruning Program Reliability Results

Cycle Pruning Project Year	AVG Annual CI Pre-Project	Total CI 1st Year Post-Project	% Improved	Total CI 2nd Year Post-Project	% Improved	Total CI 3rd Year Post-Project	% Improved
2007	55,494	60,868	-10%	48,121	13%	39,215	29%
2008	47,466	30,333	36%	28,356	40%	82,400	-74%
2009	50,362	38,327	24%	56,979	-13%	48,734	3%
2010	58,009	53,466	8%	48,340	17%	23,332	60%
2011	77,634	26,171	66%	33,166	57%	16,592	79%
2012	30,322	21,523	29%	15,864	48%	19,058	37%
2013	18,923	12,441	34%	16,180	14%	29,171	-54%
2014	26,964	22,939	15%	37,294	-38%	30,131	-12%
2015	23,451	31,726	-35%	20,122	14%	43,102	-84%
2016	15,606	27,162	-74%	21,859	-40%	58,315	-274%
2017	17,066	14,982	12%	33,116	-94%	21,141	-24%
2018	26,399	40,527	-54%	43,030	-63%	-	-
2019	21,842	35,990	-65%	-	-	-	-
Totals	469,539	416,455	11%	402,427	10%	411,191	2%

* Negative numbers represent an increase from established baseline value.

While the results for the Cycle Pruning Program are less consistent than the reliability results from the EHTM Program, this study demonstrates that the Company's Cycle Pruning Program creates, on average, a 11% improvement in reliability in the first year, 10% in the second year, and 2% in the third year following project completion. These modest improvements in reliability are attributable to the fact that the Cycle Pruning Program is designed to maintain safe and reliable electric service, as opposed to the EHTM Program which is designed to improve reliability.

In an effort to normalize the data used to show the benefits of the EHTM Program, the Company compared state-wide tree-related CI's for the same fiscal years as shown previously.

In the table below, the % Improvement column on the far right clearly shows that the EHTM Program has provided statistically significant reliability benefits.

Section 3 – Chart 4
EHTM Program Benefits Compared to Statewide Performance

	Average Annual CI Pre-Project	Average Annual CI - Post-Project (all full years available)	% Improvement
FY 2008 (3 years of data post-project)			
EHTM Feeders	22,127	9,734	56%
All RI Feeders (State-wide)	103,442	87,826	15%
FY 2009 (3 years of data post-project)			
EHTM Feeders	32,092	10,511	67%
All RI Feeders (State-wide)	117,673	94,133	20%
FY 2010 (3 years of data post-project)			
EHTM Feeders	50,145	10,670	79%
All RI Feeders (State-wide)	99,345	98,612	1%
FY 2011 (3 years of data post-project)			
EHTM Feeders	1,133	271	76%
All RI Feeders (State-wide)	93,243	86,832	7%
FY 2012 (3 years of data post-project)			
EHTM Feeders	8,601	1,784	79%
All RI Feeders (State-wide)	87,826	77,696	12%
FY 2013 (3 year of data post-project)			
EHTM Feeders	15,109	4,541	70%
All RI Feeders (State-wide)	94,133	84,265	10%
FY 2014 (3 year of data post-project)			
EHTM Feeders	13,048	4,408	66%
All RI Feeders (State-wide)	98,612	98,954	0%
FY 2015 (3 years of data post-project)			
EHTM Feeders	10,902	13,125	-20%
All RI Feeders (State-wide)	86,832	107,485	-24%
FY 2016 (3 years of data post-project)			
EHTM Feeders	4,060	520	87%
All RI Feeders (State-wide)	77,696	124,670	-60%
FY 2017 (3 year of data post-project)			
EHTM Feeders	8,861	7,171	19%
All RI Feeders (State-wide)	84,265	138,078	-64%
FY 2018 (2 year of data post-project)			
EHTM Feeders	8,573	3,935	54%
All RI Feeders (State-wide)	98,954	158,453	-60%
FY 2019 (1 year of data post-project)			
EHTM Feeders	8,549	2,008	77%
All RI Feeders (State-wide)	107,485	146,072	-36%

Damage Restoration Cost-Benefit for the EHTM Program

The Company does not have the ability to track actual repair costs by event, so estimates were created to perform analysis of the damage restoration cost benefit. The Company generated repair cost estimates for the following types of repairs: replacing a blown fuse, replacing a broken cross-arm, and replacing a broken pole. The Company then reviewed actual interruption records for the EHTM Program feeders for three years pre-project and for three years post-project. The Company estimated the required capital and expense repair work costs using the event description record and information regarding any other work required, such as removing a tree or trimming vines. The table below includes the results of the calculation of repair costs on the EHTM Program feeders for both pre-project and post-project periods. In summary, there is a 3% average reduction in annual repair costs on a circuit where the EHTM Program has been employed.

Section 3 – Chart 5
Damage Restoration Cost Reductions

Circuit	Annual AVG Repair Costs Pre-Project	Annual AVG Repair Costs Post-Project (3 Years Max.)	% Improvement
49_53_13F2	$ 566	$ 229	60%
49_53_34F2	$ 1,877	$ 601.32	68%
49_53_51F1	$ 1,938	$ 722	63%
49_53_69F1	$ 203	$ 655	-223%
49_56_33F4	$ 745	$ 1,137	-53%
49_56_54F1	$ 6,040	$ 5,701.32	6%
49_56_63F6	$ 916	$ 1,042	-14%
49_53_102W51	$ 206	$ -	100%
49_53_112W42	$ 677	$ 419	38%
49_53_2291	$ -	$ -	-
49_53_23F1	$ 1,289	$ 341	74%
49_53_38F1	$ 2,014	$ 2,176	-8%
49_53_5F4	$ 1,166	$ 206	82%
49_56_22F4	$ 719	$ 588	18%
49_56_30F1	$ 3,959	$ 772	80%
49_56_52F3	$ 2,069	$ 660	68%
49_53_108W62	$ 41	$ -	100%
49_53_20F2	$ 63	$ -	100%
49_53_38F5	$ 1,504	$ 2,449	-63%
49_53_5F2	$ 1,202	$ 1,330	-11%
49_53_5F3	$ 538	$ 951	-77%
49_53_7F1	$ 41	$ 332	-719%
49_56_16F1	$ 1,095	$ 1,845	-69%
49_56_17F2	$ 462	$ 1,817	-293%

Circuit	Annual AVG Repair Costs Pre-Project	Annual AVG Repair Costs Post-Project (3 Years Max.)	% Improvement
49_56_42F1	$ 1,617	$ 1,601	1%
49_56_43F1	$ 3,210	$ 5,764	-80%
49_56_46F2	$ 3,343	$ 3,141	6%
49_56_59F4	$ 462	$ 319	31%
49_56_72F3	$ 978	$ 837	14%
49_53_38F5	$ 1,129	$ 3,970	-252%
49_53_112W44	$ 6,381	$ 4,561	29%
49_53_126W41	$ 3,572	$ 4,886	-37%
49_53_15F1	$ 1,736	$ 547	68%
49_53_34F3	$ 8,601	$ 9,928	-15%
49_56_43F1	$ 11,830	$ 8,906	25%
49_56_59F4	$ 2,785	$ 2,093	25%
49_53_107W83	$ 99	$ 656	-563%
49_53_126W41	$ 5,213	$ 5,863	-12%
49_53_15F1	$ 5,805	$ 2,530	56%
49_53_18F6	$ 6,095	$ 2,639	57%
49_53_27F1	$ 1,669	$ 1,688	-1%
49_53_38F4	$ 3,192	$ 2,262	29%
49_53_4F1	$ 2,983	$ 1,607	46%
49_53_4F2	$ 6,061	$ 4,666	23%
49_56_14F1	$ 2,271	$ 1,630	28%
49_56_22F2	$ 3,261	$ 570	83%
49_56_57J2	$ 175	$ 341	-95%
49_56_57J5	$ 364	$ 351	4%
49_56_68F3	$ 8,453	$ 8,705	-3%
49_56_88F5	$ 7,802	$ 11,634	-49%
49_53_112W42	$ 4,250	$ 2,212	48%
49_53_112W41	$ 1,231	$ 785	36%
49_53_18F7	$ 2,031	$ 732	64%
49_56_33F3	$ 10,254	$ 9,544	7%
49_56_33F1	$ 4,860	$ 3,033	38%
49_56_33F2	$ 3,285	$ 844	74%
49_56_38K23	$ -	$ -	-
49_53_21F1	$ 3,699	$ 4,764	-29%
49_53_21F2	$ 4,327	$ 2,988	31%
49_53_21F4	$ 1,260	$ 2,377	-89%
49_53_34F2	$ 16,866	$ 14,017	17%
49_53_38F1	$ 11,533	$ 17,810	-54%
49_56_54F1	$ 18,195	$ 23,325	-28%
49_56_63F3	$ 5,167	$ 5,980	-16%
49_56_63F6	$ 9,486	$ 12,480	-32%
49_56_85T3	$ 10,222	$ 7,243	29%
49_56_40F1	$ 122	$ -	100%
49_56_41F1	$ 11,113	$ 2,056	81%
49_56_88F3	$ 8,613	$ 7,598	12%
49_56_37W41	$ 1,689	$ 1,984	-17%
49_56_37W42	$ 969	$ 206	79%
49_56_37W43	$ 512	$ 256	50%
49_53_34F1	$ 14,073	$ 30,489	-117%
49_56_30F1	$ 4,591	$ 2,248	51%
49_56_30F2	$ 12,663	$ 11,714	7%
49_56_46F3	$ 3,339	$ 1,458	56%
49_56_88F1	$ 5,590	$ 6,657	-19%
49_56_33F1	$ 3,037	$ 997	67%
49_56_33F2	$ 1,373	$ 2,632	-92%
49_56_33F3	$ 8,298	$ 5,745	31%
49_56_33F4	$ 9,467	$ 10,016	-6%
49_56_88F1	$ 6,755	$ 6,903	-2%
49_56_88F5	$ 6,018	$ 6,391	-6%
49_53_15F2	$ 9,987	$ 6,094	39%
49_56_33F4	$ 15,038	$ 12,345	18%
49_56_59F1	$ 2,556	$ 1,872	27%
49_56_68F1	$ 9,492	$ 11,967	-26%
Totals	**$ 370,379**	**$ 353,431**	**5%**

The Company also calculated the total cost benefit for the EHTM Program by program year. This calculation is made by dividing the total program cost, in this case the actual annual spend for the EHTM Program, by the CI benefit or change. The table below shows the calculation and the benefit as a rolling index over the three years' post-project completion.

Section 3 – Chart 6

EHTM Program Cost-Benefit ($/ΔCI)

		Post-Project Year 1		Post-Project Year 2		Post-Project Year 3	
Project Year	EHTM Cost	Δ CI	$ / Δ CI	Average Δ CI	$ / Δ CI	Average Δ CI	$ / Δ CI
2008	$ 579,857	9,614	$ 60	12,132	$ 48	12,393	$ 47
2009	$ 497,187	25,544	$ 19	24,311	$ 20	21,581	$ 23
2010	$ 486,681	43,414	$ 11	40,264	$ 12	39,476	$ 12
2011	$ 69,256	947	$ 73	828	$ 84	931	$ 74
2012	$ 560,213	5,629	$ 98	6,854	$ 82	6,817	$ 82
2013	$ 752,577	11,293	$ 67	11,185	$ 67	10,568	$ 71
2014	$ 474,608	12,420	$ 38	7,840	$ 61	8,640	$ 55
2015	$ 763,559	(1,896)	$ (403)	(3,370)	$ (227)	(2,224)	$ (343)
2016	$ 646,253	3,285	$ 197	3,533	$ 183	3,540	183
2017	$ 614,706	5,667	$ 108	1,749	351	1,690	364
2018	$ 935,624	3,098	$ 302	4,638	202	-	-
2019	$ 500,275	6,541	$ 76	-	-	-	-
Totals	**$ 6,880,796**	**125,556**	**$ 55**	**109,964**	**$ 58**	**103,412**	**$ 53**

In summary, from FY 2008 through FY 2019, the Company spent $6.9 million on the EHTM Program. This resulted in a reduction of 125,556 CI's following the first project year at a cost of $55 per CI. The Company has seen a reduction of 109,964 CI's in year two prost-project, and an associated cost of $58 per CI. After three years, the Company sees an average reduction of 103,412 Cis at a cost of $53 per CI.

Using the same method as the EHTM Program, the table below shows the $/ΔCI for the Cycle Pruning Program.

Section 3 – Chart 7
Cycle Pruning Program Cost-Benefit ($/ΔCI)

		Post-Project Year 1		Post-Project Year 2		Post-Project Year 3	
Project Year	**Cycle Prune Cost**	**Δ CI**	**$ / Δ CI**	**Average Δ CI**	**$ / Δ CI**	**Average Δ CI**	**$ / Δ CI**
2009	$ 5,144,193	12,035	$ 427	2,709	$ 1,899	2,348	$ 2,191
2010	$ 4,365,639	4,543	$ 961	7,106	$ 614	16,297	$ 268
2011	$ 3,956,357	51,463	$ 77	47,966	$ 82	52,324	$ 76
2012	$ 3,919,065	8,799	$ 445	11,629	$ 337	11,507	$ 341
2013	$ 4,764,000	6,482	$ 735	4,612	$ 1,033	(341)	$ (13,958)
2014	$ 5,180,000	4,025	$ 1,287	(3,152)	$ (1,643)	(3,157)	$ (1,641)
2015	$ 4,475,000	(8,275)	$ (541)	(2,473)	$ (1,810)	(8,199)	$ (546)
2016	$ 5,414,000	(11,556)	$ (469)	(8,905)	$ (608)	(42,709)	$ (127)
2017	$ 5,050,000	2,084	$ 2,423	6,983	$ 723	(6,014)	(840)
2018	$ 5,458,000	(14,128)	$ (386)	(15,380)	$ (355)	-	-
2019	$ 5,995,000	(14,148)	$ (424)	-	-	-	-
Totals	**$ 53,721,254**	**41,325**	**$ 1,300**	**51,095**	**$ 934**	**22,056**	**$ 1,916**

In summary, from FY 2009 through FY 2019, the Company spent $53.7 million on cycle pruning. This resulted in a reduction of 41,325 CI's following the first project year, resulting in a unit cost reduction of $1,300 per CI. Using two years of data, resulted in a reduction of 51,095 CI's, resulting in a unit cost reduction of $934 per CI. Using three years of data, resulted in a reduction of 22,056 CI's, resulting in a unit cost reduction of $19,16 per CI. Again, an established Cycle Pruning Program is mainly designed to maintain reliability levels with the potential to only produce modest improvements in CI, all while providing very important public and worker safety benefits.

Section 4
I&M and O&M

Section 4

Inspection and Maintenance and Other O&M
FY 2022 Electric ISR Plan

Section 4: FY 2022 Inspection and Maintenance (I&M) Plan & Other O&M

Inspection and Maintenance Program

Consistent with the Company's condition-based asset management approach, the Company has an I&M program to achieve a five-year inspection cycle of the overhead and underground assets. This program is intended to address deteriorated assets to ensure that the distribution and sub-transmission system is safe, reliable, and environmentally sound. Asset replacement prior to failure provides incremental safety benefits for both the public and our employees. In addition to asset replacement, testing for elevated voltage should minimize potential safety issues related to contact voltage on publicly accessible Company-owned distribution and sub-transmission overhead and underground line facilities. The Company recently streamlined the I&M program to only address priority items including Level 1s, Level 9s, potted porcelain cutouts and some guying issues. Level 1 maintenance items are repaired or replaced within 30 days. Level 9 priority conditions are targeted for completion within 90 days. For any Level 9 priority conditions not completed within 90 days, the Company periodically performs site visits to monitor the condition of the temporary repair. Potted porcelain cutouts and guying issues depend on site specific detail and severity of the condition. This streamlined I&M program allows the Company to address the backlog of work identified in previous years to progress. Though Level 2s and 3s are no longer captured in the I&M program, Level 2 and Level 3 issues identified in past years will be progressed as needed and as the budget allows.

Periodic inspection of equipment also provides for the avoidance of potential environmental problems such as insulating fluid leaks/spills from assets such as transformers and capacitor banks. The program is also intended to satisfy section 214 of the National Electric Safety Code, which outlines inspection of equipment guidelines for electric utilities.

In addition to addressing deteriorated assets, the data collected during the inspections enhances the Company's Asset Management reviews and the development of projects and programs to maintain reliability performance and customer satisfaction. As discussed in Section 2, deteriorated equipment is one of the top three drivers affecting customers, accounting for 14 percent of all interruptions in FY 2020. Although the I&M program is not a reliability-based program, the Company believes that the program is an essential component to fulfilling its obligation to provide safe, reliable, and cost-effective electric delivery service to customers in Rhode Island

The Company's proposal for each of the program components is as follows:

- The proposed FY 2022 Plan is designed to be year one of the third five-year inspection cycle and the continuation of repair work for items identified during previous inspection cycles. The second five-year cycle for all distribution overhead I&M inspections will be completed on schedule at the end of FY 2021.
- Underground I&M inspections will continue to be performed as part of normal working inspections.
- Overhead Manual Contact Voltage testing will be performed as part of the cycle inspections.
- Underground Manual Contact Voltage testing will continue on a five-year cycle.
- Street Light Manual Contact Voltage testing will continue on a three-year cycle.

- Mobile Contact Voltage Testing in FY 2022 will test 20 percent of the Designated Contact Voltage Risk Areas (DCVRA's) designated in Docket No. 4237-A.

FY 2022 Inspection and Maintenance Budget

As shown in Chart 1 below, the Company proposes an I&M program O&M budget of $0.9 million for FY 2022. Associated capital costs, which are included in the capital budget in Section 2 of this Electric ISR Plan, and the operating expense (OpEx) related to capital investment (CapEx), and removal costs, which are OpEx costs necessary to complete the capital construction and removal, are $3.0 million, $0.4 million and $0.2 million, respectively.

Section 4 – Chart 1
FY 2022 I&M Program Costs
($000)

I&M Program Spending	O&M	Capital	Cost of Removal
I&M Program Spending	$475	$3,000	$240
I&M Opex Related to Capex	421	0	0
Total	**$896**	**$3,000**	**$240**

Other O&M Budget

As discussed in Section 2, the Company continues to deploy VVO/CVR on targeted feeders. The intent of this project is to flatten and lower the feeder voltage profile using additional voltage monitors along the feeder and centralize control of the regulating devices based on real time system performance. This project has ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing. As shown on the table below, in FY 2022 the Company has budgeted O&M spending $0.3 million.

For FY 2022, the Company's proposes a budget of $25,000 for continuing the development of the Long Range Plan in FY 2021.

Section 4 – Chart 2
FY 2022 Other O&M Costs
($000)

Other O&M Spending	O&M
VVO/CVR	$262
System Planning & Protection Coordination Study	25
Total	**$287**

The following sections listed below are following:

Section 5 – Revenue Requirement

Section 6 – Rate Design

Section 7 – Bill Impacts

Section 5
Revenue Requirement

Section 5

Revenue Requirement
FY 2022 Electric ISR Plan

Section 5: Revenue Requirement FY 2022 Proposal

Introduction

The attached proposed revenue requirement calculation reflects the revenue requirement related to the Company's proposed investment in its Electric ISR Plan for the fiscal year (FY) ended March 31, 2022.

As shown on Attachment 1, Page 1, Column (b), the Company's FY 2022 Electric ISR Plan cumulative revenue requirement is $41,433,447 and consists of the following elements: (1) operation and maintenance (O&M) expense associated with the Company's vegetation management (VM) activities, the Company's Inspection and Maintenance (I&M) program, and other programs, (2) the Company's capital investment in electric utility infrastructure, and (3) the FY 2022 Property Tax Recovery Adjustment. Lines 1, 2, and 3 of Column (b) reflect the forecasted FY 2022 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $10,800,000, $896,000, and $287,000, respectively, which are described in Section 3 and Section 4 of this document.

The FY 2022 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $29,460,447 is shown on Attachment 1, Page 1, Line 13. This amount includes (1) the $3,644,310 revenue requirement on FY 2022 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 18, (2) the FY 2022 revenue requirements on incremental ISR capital investment for FY 2018 through FY 2021 totaling $20,743,961 and (3) the FY 2022 Property Tax Recovery Adjustment of $5,072,176 from Attachment 1, Page 27. Importantly, the incremental capital investment for the FY 2022

Electric ISR revenue requirement excludes capital investment embedded in base rates in Docket No. 4770 for FY 2018 through FY 2022. Incremental electric capital investment for this purpose is defined as cumulative allowed capital plus cost of removal, less annual depreciation expense embedded in the Company's base rates, net of depreciation expense attributable to general plant. The total annual FY 2022 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $41,443,447, as reflected on Attachment 1, Page 1, Column (b) on Line 14, and is equal to the sum of Lines 4 and 13. Finally, Line 15 reflects the incremental FY 2022 revenue requirement of $8,501,929 above the FY 2021 ISR Plan revenue requirement.

For illustration purposes only, Column (c) of Page 1 provides the FY 2023 revenue requirement for the respective vintage year capital investments. These amounts will be trued up to actual investment activity after the conclusion of the FY, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

Operation and Maintenance Expenses

As previously noted, the Company's FY 2022 Electric ISR Plan revenue requirement includes $10,800,000 of VM expenses, $896,000 of I&M expenses, and $287,000 of Other Program O&M expenses as shown on Page 1, Lines 1 through 3 in Column (b) of the Attachment.

Electric Infrastructure Investment

Incremental Capital Investment

Page 18 of Attachment 1 to this Section calculates the revenue requirement of incremental capital investment associated with the Company's FY 2022 Electric ISR Plan; that is, electric infrastructure investment (net of general plant) incremental to the amounts embedded in the Company's base distribution rates. The proposed capital investment and estimated cost of removal were obtained from Chart 18 of Section 2 in this Plan. The FY 2022 revenue requirement also includes the incremental capital investment associated with the Company's FY 2018 through FY 2021 Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4770 for FY 2018 through FY 2021. Page 21 of Attachment 1 calculates the incremental FY 2018 through FY 2022 ISR capital investment and the related incremental cost of removal, incremental retirements, and incremental net operating loss (NOL) position for the FY 2022 electric ISR revenue requirement. The calculations on Page 21 compare ISR-eligible capital investment, cost of removal, retirements, and net NOL position for FY 2018 through FY 2022 to the corresponding amounts reflected in Docket No. 4770.

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. This ISR plan limits the amount of eligible discretionary capital investments to the annual movement in the lesser of cumulative discretionary capital additions, cumulative actual discretionary capital spending or cumulative approved discretionary capital spending since April 1, 2011 (the inception date of the ISR). This limitation on discretionary capital investment will be analyzed as a part of the previously mentioned annual reconciliation of the proposed ISR investment to actual investment activity after the conclusion of the fiscal year.

Incremental Capital Investment Calculation

The ISR mechanism was established to allow the Company to recover outside of base rates its costs associated with plant additions incurred to expand its electric infrastructure and improve the reliability and safety of its electric facilities. When new base rates are implemented, as was the case in Docket No. 4770, the costs the Company recovers for pre-rate case ISR plant additions are no longer through a separate ISR factor. Instead, these costs are recovered through base rates, and the underlying ISR plant additions become a component of base distribution rate base from that point forward. The forecast used to develop rate base in the distribution rate case included ISR plant additions levels for FY 2018, FY 2019, and five months of FY 2020 (using the level of plant additions approved in the FY 2018 ISR Plan Proposal as a proxy for FY 2019 and FY 2020). The effective date of new rates in Docket No. 4770 was September 1, 2018. Therefore, recovery of the approved FY 2012 through FY 2019 ISR revenue requirement through the ISR factor stopped on August 31, 2018, and all future recovery of those ISR plant additions are through the Company's base rates.

As a result of the implementation of new base distribution rates established in Docket No. 4770 effective September 1, 2018, the cumulative amount of forecasted ISR plant additions were included in rate base to be recovered through base distribution rates effective as of that date. The FY 2022 revenue requirement for incremental FY 2018, FY 2019, FY 2020, FY 2021 and FY 2022 ISR investments reflect a full year of revenue requirement because none of these incremental investments are included in the Company's rate base. As a result, these incremental FY vintage amounts must remain in the ISR recovery mechanism as provided for in the terms of the approved amended settlement in Docket No. 4770. This filing is based on the actual ISR plant additions for the fiscal years ended March 31, 2018, March 31, 2019, and March 31, 2020 and the estimated ISR plant additions for the Company's fiscal years ended March 31, 2021 and March 31, 2022, which are incremental to the levels reflected in rate base in Docket No. 4770.

Electric Infrastructure Revenue Requirement

The revenue requirement calculation on incremental electric infrastructure investment for vintage year FY 2022 is shown on Page 18 of Attachment 1. The revenue requirement calculation incorporates the incremental Electric ISR Plan capital investment, cost of removal, retirements, and NOL position. The calculation on Page 18 begins with the determination of the depreciable net incremental capital that will be included in the ISR Plan rate base. Because depreciation expense is affected by plant retirements, retirements have been deducted from the total allowed capital included in ISR Plan rate base in determining depreciation expense. Retirements, however, do not affect rate base because both plant-in-service and the depreciation reserve are reduced by the installed value of the plant being retired and therefore have no impact on net plant. For purposes of calculating the revenue requirement, incremental plant retirements have been estimated based on the three- year average percentage of retirements to additions during FY 2018 through FY 2020 and have been deducted from the total depreciable capital amount as shown on Page 18, Lines 4 through 6. Incremental book depreciation expense on Line 16 is computed based on the net depreciable additions, from Line 6 at the 3.16 percent composite depreciation rate as approved in Docket No. 4770, and as shown on Line 12. The Company has assumed a half year convention for the year of installation. Unlike retirements, cost of removal affects rate base but not depreciation expense. Consequently, the cost of removal, as shown on Line 10, is combined with the incremental depreciable amount from Line 9 (vintage year ISR Plan allowable capital additions less depreciation expense related to non-general plant except for communication equipment included in base distribution rates) to arrive at the incremental investment on Line 11 to be included in the rate base upon which the return component of the annual revenue requirement is calculated.

The rate base calculation incorporates net plant from Line 11 and accumulated depreciation and accumulated deferred tax reserves, as shown on Lines 17 and 22, respectively. The deferred tax amount arising from the capital investment, as calculated on Lines 18 through 22, equals the difference between book depreciation and tax depreciation on the capital investment, times the effective tax rate, net of any incremental tax NOL or NOL Utilization. The calculation of tax depreciation is described below. The average rate base before the adjustment for deferred tax proration is shown on Line 27. This amount is then adjusted for deferred tax proration on Line 28 to derive the average rate base for ISR on Line 29. The average rate base is multiplied by the pre-tax rate of return approved by the Commission in Docket No. 4770, as shown on Line 30, to compute the return and tax portion of the incremental revenue requirement, as shown on Line 31. As reflected on Line 32, incremental depreciation expense is added to this amount. The sum of these amounts reflects the annual revenue requirement associated with the incremental capital investment portion of the Company's Electric ISR Plan on Line 33, which is carried forward to Page 1, Line 9, as part of the total Electric ISR Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2018, FY 2019, FY 2020 and FY 2021 incremental ISR Plan capital investments are shown on Attachment 1 at Pages 2, 5, 10 and 14. These capital investment revenue requirement amounts are added to the total O&M expenses on Attachment 1, Page 1, Line 4, as well as the property tax amount on Page 1, Line 12 to derive the total FY 2022 Electric ISR Plan revenue requirement of $41,443,447 as shown on Page 1, Line 14.

Tax Depreciation Calculation

The tax depreciation calculation for FY 2022 is provided on Attachment 1, Page 19. The tax depreciation amount assumes that a portion of the incremental capital investment, as shown on Line 1 of Page 19, will be eligible for immediate deduction on the Company's corresponding FY federal income tax return. This immediate deductibility is referred to as the capital repairs deduction.[1] In addition, plant additions not subject to the capital repairs deduction may be subject to bonus depreciation as shown on Page 19, Lines 4 through 12 for FY 2022. In 2010,

[1] In 2009, the Internal Revenue Service (IRS) issued additional guidance, under Internal Revenue Code Section 162, related to certain work considered to be repair and maintenance expense, and which is eligible for immediate tax deduction for income tax purposes, but capitalized by the Company for book purposes. As a result of this additional guidance, the Company recorded a one-time tax expense for repair and maintenance costs in its FY

Congress passed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the Act), which provided for an extension of bonus depreciation. Specifically, the Act provides for the application of 100 percent bonus depreciation for investment constructed and placed into service after September 8, 2010 through December 31, 2011, and then 50 percent bonus depreciation for similar capital investment placed into service after December 31, 2011 through December 2012. The 50 percent bonus depreciation rate was later extended through December 31, 2013 and then extended further through December 31, 2017 through the Protecting Americans from Tax Hikes (PATH) Act. As noted in the Company's previous Electric ISR filings, the Tax Cuts and Jobs Act of 2017 (Tax Act) went into effect on December 22, 2017. The Tax Act has many elements, but two particular aspects have an impact on the Electric ISR revenue requirement. The first is the reduction of the federal income tax rate from 35 percent to 21 percent commencing January 1, 2018. The second Tax Act element affecting the Electric ISR revenue requirement is changes to the bonus depreciation rules eliminating 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. The Company's original interpretation of the 2017 Tax Act was

2009 federal income tax return filed on December 11, 2009 by National Grid Holdings, Inc. Since that time, the Company has taken a capital repairs deduction on all subsequent FY tax returns. This has formed the basis for the capital repairs deduction assumed in the Company's revenue requirement. This tax deduction has the effect of increasing deferred taxes and lowering the revenue requirement that customers will pay under the capital investment reconciliation mechanism. The Company's federal income tax returns are subject to audit by the IRS. If it is determined in the future that the Company's position on its tax returns on this matter was incorrect, the Company will reflect any related IRS disallowances, plus any associated interest assessed by the IRS, in a subsequent reconciliation filing under the ISR Plan.

that no deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. However, based on current industry practice, the Company included a deduction for bonus depreciation on its FY 2019 tax return and revised its estimate of FY 2020 bonus depreciation. The Company's FY 2022 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2022 investment.

Finally, the remaining plant additions not deducted as bonus depreciation are then subject to the IRS Modified Accelerated Cost-Recovery System (MACRS) tax depreciation rate. Also, the IRS clarified its tangible property regulations, and, consequently, the Company submitted a §481(a) election with the IRS to apply for a change in accounting method regarding the treatment of gains or losses on asset retirements, which are characterized as partial retirements for tax purposes. This election was submitted to the Commission, as required under IRS rules, on December 17, 2015. The late partial disposition election was made to protect the Company's deduction of cost of removal (COR). Otherwise, the Company would have been required to make a §481(a) adjustment to reverse all historical COR deductions, resulting in a substantial reduction in deferred tax liabilities. Because the Company made the election, COR remains 100% deductible. The vintage FY 2018 through FY 2022 tax depreciation calculations in this filing include an additional tax deduction related to this change in accounting issue. The total amount of tax depreciation equals the amount of capital repairs deduction plus the bonus depreciation deduction, MACRS depreciation, the tax loss on retirements, and cost of removal. These annual total tax depreciation amounts are carried over to Page 18 of Attachment 1, Line 14 and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for FY 2018, FY 2019, FY 2020 and FY 2021 on Attachment 1, Pages 3, 6, 11 and 15.

The Company continues to monitor for new guidance pertaining to the Tax Act and any resulting impacts to its pending rate requests. The Company files its FY 2020 tax return in December 2020. At that time, the Company will evaluate whether any revisions are required to its calculation of accumulated deferred income taxes included in rate base in the FY 2020, FY 2021 and FY 2022 vintage revenue requirement calculations in this docket. If so, the Company will supplement this filing with a revised FY 2022 revenue requirement calculation.

Federal Net Operating Loss

Tax net operating losses (NOLs) are generated when the Company has tax deductions on its income tax returns that exceed its taxable income. This does not mean that the Company is suffering losses in its financial statements; instead, the Company's tax NOLs are the result of the significant tax deductions that have been generated in recent years by the bonus depreciation and capital repairs tax deductions. In addition to first-year bonus tax depreciation, the US tax code allows the Company to classify certain costs as repairs expense, which the Company takes as an immediate deduction on its income tax return; however, these costs are recorded as plant investment on the Company's books. These significant bonus depreciation and capital repairs tax deductions had exceeded the amount of taxable income reported in tax returns filed for FY 2009 to FY 2018, with the exception of FY 2011 and FY 2017. NOLs are recorded as non-cash assets on the Company's balance sheet and represent a benefit that the Company and customers will receive when the Company is able to realize actual cash savings and applies these NOLs against taxable income in the future.

As a result of the 2017 Tax Act, the Company originally did not expect to generate new NOLs in FY 2018 or FY 2019 and anticipated it would begin to utilize prior years' NOLs in FY 2020. Therefore, estimated NOL utilization is included in base rates in Docket 4770, and the calculation of accumulated deferred income taxes in this filing includes only the incremental amount of forecasted NOL utilization in FY 2022, which is the fiscal year in which the benefit would be reflected in the Company's federal income tax return. The Company revised its estimated NOL utilization for FY 2021 which has been reflected in this FY 2022 revenue requirement calculation.

NOL utilization increases the Company's accumulated deferred income taxes. Accumulated deferred income taxes, which equals the difference between book depreciation and tax depreciation on ISR capital investment times the effective rate, are included as a credit or reduction in the calculation of rate base.

<u>Accumulated Deferred Income Tax Proration Adjustment</u>

The Electric ISR Plan includes a proration calculation regarding the accumulated deferred income tax balance included in rate base. The calculation fulfills requirements set out under IRS Regulation 26 C.F.R. §1.167(1)-1(h)(6). This regulation stipulates normalization requirements for regulated entities so that the benefits of accelerated depreciation are not passed back to customers too quickly. The penalty of a normalization violation is the loss of all federal income tax deductions for accelerated depreciation, including bonus depreciation. Any regulatory filing that includes capital expenditures, book depreciation expense and accumulated deferred income tax related to those capital expenditures must follow the normalization requirements. When the regulatory filing is based on a future period, the deferred tax must be prorated to reflect the period of time that the accumulated deferred tax balances are in rate base. This filing includes FY 2018, FY 2019, FY 2020, FY 2021 and FY 2022 proration calculations at Pages 4, 7, 12, 17 and 20, respectively, the effects of which are included in each year's respective revenue requirement.

<u>Property Tax Recovery Adjustment</u>

The Property Tax Recovery Adjustment is shown on Pages 26 and 27 of Attachment 1. The method used to recover property tax expense under the ISR was modified by the rate case settlement agreement in Docket No. 4323 and continued under the amended settlement agreement in Docket No. 4770. In determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company includes an amount equal to the base-rate allowance for depreciation expense and depreciation expense on incremental ISR plant additions in the accumulated reserve for depreciation that is deducted from plant in service. The ISR property tax recovery adjustment also includes the impact of any changes in the Company's effective property tax rates on base-rate embedded property, plus cumulative ISR net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery calculation. The FY 2022 revenue requirement includes $5,072,176 for the net property tax recovery adjustment, as shown on Page 1, Line 12.

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

Line No.		Approved Fiscal Year 2021 (a)	Fiscal Year 2022 (b)	Fiscal Year 2023 (c)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$10,600,000	$10,800,000	
2	Current Year Inspection & Maintenance (I&M)	$1,035,000	$896,000	
3	Current Year Other Programs	$456,633	$287,000	
4	**Total O&M Expense Component of Revenue Requirement**	**$12,091,633**	**$11,983,000**	**$0**
	Capital Investment:			
5	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$2,057,064	$2,001,528	$1,946,604
6	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$4,272,652	$4,115,670	$3,965,256
7	Actual Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$5,226,171	$5,902,936	$5,692,039
8	Forecasted Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base	$4,341,988	$8,723,827	$8,407,931
9	Forecasted Revenue Requirement on FY 2022 Incremental Capital included in ISR Rate Base	$0	$3,644,310	$7,137,990
10	Subtotal	$15,897,876	$24,388,271	$27,149,820
11	FY 2021 Property Tax Recovery Adjustment	$4,952,008		
12	FY 2022 Property Tax Recovery Adjustment		$5,072,176	
13	**Total Capital Investment Component of Revenue Requirement**	**$20,849,885**	**$29,460,447**	**$27,149,820**
14	**Total Fiscal Year Revenue Requirement**	**$32,941,518**	**$41,443,447**	**$27,149,820**
15	**Incremental Fiscal Year Rate Adjustment**		**$8,501,929**	

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 3, Chart 1
2 Other Operations and Maintenance, Section 4, Chart 1
3 Other Operations and Maintenance, Section 4, Chart 2
4 Sum of Lines 1 through 3
5 Page 2 of 29, Line 34 Column (e) & (f)
6 Page 5 of 29, Line 36, Column (d) & (e)
7 Page 10 of 29, Line , Column (c) & (d)
8 Page 14 of 29, Line , Column (b) & (c)
9 Page 18 of 29, Line , Column (a) & (b)
10 Sum of Lines 5 through 9
12 Page 27 of 29, Line 52, Column (k) × 1,000
13 Sum of Lines 10 through 12
14 Line 4 + Line 13
15 Line 14 Col (b) - Line 14 Col (a)

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
FY 2022 Revenue Requirement on FY 2018 Actual Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)	Fiscal Year 2023 (f)
	Capital Investment Allowance								
1	*Non-Discretionary Capital*			$3,178,398					
	Discretionary Capital								
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$14,638,256					
3	Total Allowed Capital Included in Rate Base	Page 21 of 29, Line 4(a)		$17,816,654	$0	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base								
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$17,816,654	$0	$0	$0	$0	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (a)		($5,245,072)	$0	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726
	Change in Net Capital Included in Rate Base								
7	Capital Included in Rate Base	Line 3		$17,816,654	$0	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (a)		$1,719,991	$0	$0	$0	$0	$0
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year		**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**	**$19,536,645**
	Deferred Tax Calculation:								
12	Composite Book Depreciation Rate	As approved per RIPUC Docket No. 4323 and Docket No. 4770	1/	3.40%	3.26%	3.16%	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:								
14	2018 Spend	Year 1 = Page 3 of 29, Line 23; then = Page 3 of 29, Column (d)		$13,898,861	$571,028	$528,156	$488,605	$451,903	$418,047
15	Cumulative Tax Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14		$13,898,861	$14,469,889	$14,998,045	$15,486,650	$15,938,553	$16,356,600
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12		$392,049	$751,812	$728,751	$728,751	$728,751	$728,751
17	Cumulative Book Depreciation	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$392,049	$1,143,862	$1,872,612	$2,601,363	$3,330,113	$4,058,864
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$13,506,812	$13,326,028	$13,125,433	$12,885,287	$12,608,439	$12,297,736
19	Effective Tax Rate		2/	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$2,836,430	$2,798,466	$2,756,341	$2,705,910	$2,647,772	$2,582,525
21	Less: FY 2018 Federal NOL	Year 1 = Page 21 of 29 , Line 15 ,Col (a) ; then = Prior Year Line 21		($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)
22	Excess Deferred Tax	Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1		$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969
23	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 22		$1,262,901	$1,224,936	$1,182,811	$1,132,380	$1,074,242	$1,008,995
	Rate Base Calculation:								
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645
25	Accumulated Depreciation	-Line 17		($392,049)	($1,143,862)	($1,872,612)	($2,601,363)	($3,330,113)	($4,058,864)
26	Deferred Tax Reserve	-Line 23		($1,262,901)	($1,224,936)	($1,182,811)	($1,132,380)	($1,074,242)	($1,008,995)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$17,881,695	$17,167,848	$16,481,222	$15,802,902	$15,132,290	$14,468,787
	Revenue Requirement Calculation:								
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 27 ÷ 2; then Average of (Prior + Current Year Line 27)						$15,467,596	$14,800,538
29	Proration Adjustment	Y 1 = N/A; Y 2 = 0; Y 3 = Page 4 of 29, Line 41(l)						($2,495)	($2,801)
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29						$15,465,101	$14,797,738
31	Pre-Tax ROR	Page 28 of 29, Line 35						8.23%	8.23%
32	Return and Taxes	Line 30 * Line 31						$1,272,778	$1,217,854
33	Book Depreciation	Line 16						$728,751	$728,751
34	**Annual Revenue Requirement**	Line 32 + Line 33		**N/A**	**N/A**	**N/A**	**N/A**	**$2,001,528**	**$1,946,604**

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 January 1, 2018 per the Tax Cuts and Jobs Act of 2017

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
Calculation of Tax Depreciation and Repairs Deduction on FY 2018 Incremental Capital Investments

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

20 Year MACRS Depreciation

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

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

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2018 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**			(a) FY22	(b) FY23
1	Book Depreciation	Page 2 of 29, Line 33, column (e) & (f)		$728,751	$728,751
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	Page 3 of 29, Line 8, column, (d)		($451,903)	($418,047)
4	FY18 tax (gain)/loss on retirements			$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		$276,848	$310,703
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		$58,138	$65,248
	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				
12	Effective Tax Rate				
13	Deferred Tax Reserve				
14	Total Deferred Tax Reserve	Line 7 + Line 13		$58,138	$65,248
15	Net Operating Loss				
16	Net Deferred Tax Reserve	Line 14 + Line 15		$58,138	$65,248
	Allocation of FY 2018 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration				
18	Cumulative Book/Tax Timer Not Subject to Proration				
19	Total Cumulative Book/Tax Timer				
20	Total FY 2018 Federal NOL				
21	Allocated FY 2018 Federal NOL Not Subject to Proration				
22	Allocated FY 2018 Federal NOL Subject to Proration				
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration				
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		$58,138	$65,248
	Proration Calculation	(j) Number of Days in Month	(k) Proration Percentage	(l) FY22	(m) FY23
26	April	30	91.78%	$4,447	$4,990
27	May	31	83.29%	$4,035	$4,529
28	June	30	75.07%	$3,637	$4,082
29	July	31	66.58%	$3,225	$3,620
30	August	31	58.08%	$2,814	$3,158
31	September	30	49.86%	$2,416	$2,711
32	October	31	41.37%	$2,004	$2,249
33	November	30	33.15%	$1,606	$1,803
34	December	31	24.66%	$1,195	$1,341
35	January	31	16.16%	$783	$879
36	February	28	8.49%	$411	$462
37	March	31	0.00%	$0	$0
38	Total	365		$26,574	$29,823
39	Deferred Tax Without Proration	Line 25		$58,138	$65,248
40	Average Deferred Tax without Proration	Line 25 * 50%		$29,069	$32,624
41	Proration Adjustment	Line 38 - Line 40		($2,495)	($2,801)

Column Notes:

(a)	Docket no. 4915, Revised section 5, Att. 1S, Page 4 of 19, Col (a)
(k)	Sum of remaining days in the year (Col (j)) ÷ 365
(l) through (m)	Current Year Line 25 ÷ 12 × Current Month Col (k)

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
FY 2022 Revenue Requirement on FY 2019 Actual Incremental Capital Investment

Line No.			Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)	Fiscal Year 2022 (d)	Fiscal Year 2023 (e)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*		$7,452,659		$0	$0	$0
	Discretionary Capital						
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending		$25,486,776		$0	$0	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 21 of 29, Line 4(b)	$32,939,435	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3, Column (a)	$32,939,435	$0	$0	$0	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (b)	($10,649,479)	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6	$43,588,914	$43,588,914	$43,588,914	$43,588,914	$43,588,914
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3, Column (a)	$32,939,435	$0	$0	$0	$0
8	Depreciation Expense		$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9	$32,939,435	$32,939,435	$32,939,435	$32,939,435	$32,939,435
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (b)	$101,073				
11	**Total Net Plant in Service**	Year 1 = Line 9 + Line 10, Then = Prior year	**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	As approved per RIPUC Docket No. 4323 and Docket No. 4770 1/	3.26%	3.16%	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:						
14	2019 Spend	Year 1 = Page 6 of 29, Line 22 Then = Page 6 of 29 Column (d)	$9,919,837	$1,842,847	$1,704,487	$1,576,848	$1,458,400
15	Cumulative Tax Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14	$9,919,837	$11,762,684	$13,467,171	$15,044,019	$16,502,419
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12	$710,499	$1,377,410	$1,377,410	$1,377,410	$1,377,410
17	Cumulative Book Depreciation	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16	$710,499	$2,087,909	$3,465,319	$4,842,728	$6,220,138
18	Cumulative Book / Tax Timer	Line 15 - Line 17	$9,209,338	$9,674,775	$10,001,852	$10,201,291	$10,282,281
19	Effective Tax Rate		21.00%	21.00%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19	$1,933,961	$2,031,703	$2,100,389	$2,142,271	$2,159,279
21	Add: FY 2019 Federal NOL incremental utilization	Page 21 of 29 , Line 15 ,Col (b)	$991,622	$991,622	$991,622	$991,622	$991,622
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21	$2,925,583	$3,023,325	$3,092,011	$3,133,893	$3,150,901
	Rate Base Calculation:						
23	Cumulative Incremental Capital Included in Rate Base	Line 11	$33,040,508	$33,040,508	$33,040,508	$33,040,508	$33,040,508
24	Accumulated Depreciation	-Line 17	($710,499)	($2,087,909)	($3,465,319)	($4,842,728)	($6,220,138)
25	Deferred Tax Reserve	-Line 22	($2,925,583)	($3,023,325)	($3,092,011)	($3,133,893)	($3,150,901)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25	$29,404,426	$27,929,274	$26,483,178	$25,063,887	$23,669,469
	Revenue Requirement Calculation:						
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 26 ÷ 2; Then = (Prior Year Line 26 + Current Year Line 26) ÷ 2				$25,773,532	$24,366,678
28	Proration Adjustment	Page 7 of 29, Line 41, Column (l) ~ (n)				($339)	($3,637)
29	Average ISR Rate Base after Deferred Tax Proration	Line 27 + Line 28				$25,773,194	$24,363,041
30	Pre-Tax ROR	Page 28 of 29, Line 35				8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30				$2,121,134	$2,005,078
32	Book Depreciation	Line 16				$1,377,410	$1,377,410
33	Annual Revenue Requirement	Line 31 + Line 32				$3,498,544	$3,382,488
34	Revenue Requirement of Plant	Year 1 = Line 33*7/12, Then = Line 33				$3,498,544	$3,382,488
35	Revenue Requirement of Intangible	Page 8 of 29, Line 30, Column (d) & (e)				$617,127	$582,768
36	**Revenue Requirement**	Line 34 + Line 35	**N/A**	**N/A**	**N/A**	**$4,115,670**	**$3,965,256**

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

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

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

20 Year MACRS Depreciation

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

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

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment

Line No.			(a) FY22	(b) FY23
	Deferred Tax Subject to Proration			
1	Book Depreciation	Page 5 of 29, Line , column (d) & (e)	$1,871,785	$1,871,785
2	Bonus Depreciation		$0	$0
3	Remaining MACRS Tax Depreciation	Page 6 of 29, Line 8, column, (d)	($1,833,281)	($1,458,400)
4	FY 2019 tax (gain)/loss on retirements		$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$38,504	$413,385
6	Effective Tax Rate		21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$8,086	$86,811
	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			
12	Effective Tax Rate			
13	Deferred Tax Reserve			
14	Total Deferred Tax Reserve	Line 7 + Line 13	$8,086	$86,811
15	Net Operating Loss		$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	$8,086	$86,811
	Allocation of FY 2019 Estimated Federal NOL			
17	Cumulative Book/Tax Timer Subject to Proration			
18	Cumulative Book/Tax Timer Not Subject to Proration			
19	Total Cumulative Book/Tax Timer			
20	Total FY 2019 Federal NOL			
21	Allocated FY 2019 Federal NOL Not Subject to Proration			
22	Allocated FY 2019 Federal NOL Subject to Proration			
23	Effective Tax Rate			
24	Deferred Tax Benefit subject to proration			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	$8,086	$86,811

Line No.	**Proration Calculation**	(j) Number of Days in Month	(k) Proration Percentage	(l) FY22	(m) FY23
26	April	30	91.80%	$619	$6,641
27	May	31	83.33%	$562	$6,029
28	June	30	75.14%	$506	$5,436
29	July	31	66.67%	$449	$4,823
30	August	31	58.20%	$392	$4,210
31	September	30	50.00%	$337	$3,617
32	October	31	41.53%	$280	$3,004
33	November	30	33.33%	$225	$2,411
34	December	31	24.86%	$168	$1,799
35	January	31	16.39%	$110	$1,186
36	February	29	8.47%	$57	$613
37	March	31	0.00%	$0	$0
38	Total	366		$3,704	$39,769
39	Deferred Tax Without Proration	Line 25		$8,086	$86,811
40	Average Deferred Tax without Proration	Line 39 * 50%		$4,043	$43,405
41	Proration Adjustment	Line 38 - Line 40		($339)	($3,637)

Column Notes:

(k) Sum of remaining days in the year (Col (j)) ÷ 365

(l) Current Year Line ÷ 12 × Current Month Col (k)

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
FY 2020 Revenue Requirement on FY 2019 Intangible Investment

Line No.	Capital Investment	Reference	FY19 Total (a)	FY 20 Total (b)	FY 21 Total (c)	FY 22 Total (d)	FY 23 Total (e)
1	Start of Rev. Req. Period		09/01/18	04/01/19	04/01/20	04/01/21	04/01/22
2	End of Rev. Req. Period		03/31/19	03/31/20	03/31/21	03/31/22	03/31/23
3	Investment Name	Per Company's Book					
4	Work Order	Per Company's Book					
5	Total Spend		$3,460,626	$3,460,626	$3,460,626	$3,460,626	$3,460,626
6	In ServiceDate	Per Company's Book					
7	Book AmortizationPeriod	Per Company's Book					
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$3,378,230	$3,089,845	$2,595,470	$2,101,094	$1,606,719
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$3,089,845	$2,595,470	$2,101,094	$1,606,719	$1,112,344
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$3,234,038	$2,842,657	$2,348,282	$1,853,907	$1,359,532
	Deferred Tax Calculation:						
11	Tax Amortization Period	Page 9 of 29					
12	Tax Expensing	Per Tax Department	$0	$0	$0	$0	$0
13	Tax Bonus Rate	Per Tax Department					
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 0	$0	$0	$0	$0	$0
15	Beginning Acc. Tax Balance	(L. 5 - L. 12- L.14)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%)	$1,153,427	$1,153,427	$2,691,675	$3,204,194	$3,460,626
16	Ending Acc. Tax Balance	(L. 5 - L. 12- L.14) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$1,153,427	$2,691,675	$3,204,194	$3,460,626	$3,460,626
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$1,153,427	$1,922,551	$2,947,934	$3,332,410	$3,460,626
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$82,396	$370,781	$865,157	$1,359,532	$1,853,907
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$370,781	$865,157	$1,359,532	$1,853,907	$2,348,282
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$226,589	$617,969	$1,112,344	$1,606,719	$2,101,094
21	Average Book / Tax Timer	Line 17 - Line 20	$926,838	$1,304,582	$1,835,590	$1,725,691	$1,359,532
22	Effective Tax Rate						
23	Deferred Tax Reserve	Line 21 × Line 22	$194,636	$273,962	$385,474	$362,395	$285,502
	Rate Base Calculation:						
24	Average Book Balance	Line 10	$3,234,038	$2,842,657	$2,348,282	$1,853,907	$1,359,532
25	Deferred Tax Reserve	Line 23	$194,636	$273,962	$385,474	$362,395	$285,502
26	Average Rate Base	Line 24 - Line 25	$3,039,402	$2,568,695	$1,962,808	$1,491,512	$1,074,030
	Revenue Requirement Calculation:						
27	Pre-Tax ROR	year 1 = Page 28 of 29, Line 27, column (e)×7÷12 Then = Page 28 of 29, Line 27(e)					
28	Return and Taxes	Line 26 × Line 27	$145,917	$211,404	$161,539	$122,751	$88,393
29	Book Depreciation	Line 9 - Line 8	$288,386	$494,375	$494,375	$494,375	$494,375
30	Annual Revenue Requirement	Line 28 + Line 29	$434,302	$705,779	$655,914	$617,127	$582,768

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
MACRS Tables For Information Systems

Line	Annual Rate			Monthly Cumulative Rate				
No.	Year			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
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2022 Revenue Requirement on FY 2020 Actual Incremental Capital Investment

Line No.				Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)	Fiscal Year 2023 (d)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*	RIPUC Docket 4915, Attachment MAL-1 Compliance, Page 11		$34,127,476	$0	$0	$0
2	Less: Transformer & Related Equipment disallowance	RIPUC Docket 4915, Attachment MAL-1 Compliance, Page 11		($1,641,674)			
3	Adjusted Non-Discretionary Capital	Line 1 + Line 2		$32,485,802			
	Discretionary Capital						
4	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	RIPUC Docket 4915, Attachment MAL-1 Compliance, Page 11		$39,597,335	$0	$0	$0
5	Total Allowed Capital Included in Rate Base	Line 3 + Line 4		$72,083,137	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
6	Total Allowed Capital Included in Rate Base in Current Year	Line 5		$72,083,137	$0	$0	$0
7	Retirements	Page 21 of 29 , Line 10 ,Col (c)		$4,015,632	$0	$0	$0
8	Net Depreciable Capital Included in Rate Base	Year 1 = Line 6 - Line 7; Then = Prior Year Line 8		$68,067,505	$68,067,505	$68,067,505	$68,067,505
	Change in Net Capital Included in Rate Base						
9	Capital Included in Rate Base	Line 5		$72,083,137	$0	$0	$0
10	Depreciation Expense	Page 25 of 29, Line 41, Col (d) ×7 ÷12		$29,112,370	$0	$0	$0
11	Incremental Capital Amount	Year 1 = Line 9 - Line 10; then = Prior Year Line 11		$42,970,767	$42,970,767	$42,970,767	$42,970,767
12	Cost of Removal	Page 21 of 29 , Line 7 ,Col (c)		$10,949,557			
13	**Total Net Plant in Service**	Year 1 = Line 11 + Line 12, Then = Prior year		**$53,920,323**	**$53,920,323**	**$53,920,323**	**$53,920,323**
	Deferred Tax Calculation:						
14	Composite Book Depreciation Rate	Page 23 of 29, Line 3, Col (e)	1/	3.16%	3.16%	3.16%	3.16%
15	Vintage Year Tax Depreciation:						
16	2020 Spend	Year 1 = Page 11 of 29, Line 22 , Then = Page 11 of 29, Col (d)		$23,811,948	$4,602,526	$4,256,970	$3,938,192
17	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$23,811,948	$28,414,474	$32,671,444	$36,609,635
18	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,075,467	$2,150,933	$2,150,933	$2,150,933
19	Cumulative Book Depreciation	Year 1 = Line 16; Then = Prior Year Line 17 + Current Year Line 16		$1,075,467	$3,226,400	$5,377,333	$7,528,266
20	Cumulative Book / Tax Timer	Line 17 - Line 19		$22,736,481	$25,188,074	$27,294,111	$29,081,369
21	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
22	Deferred Tax Reserve	Line 20 * Line 21		$4,774,661	$5,289,496	$5,731,763	$6,107,088
23	Add: FY 2020 Federal NOL Utilization	Page 21 of 29, Line 15, Col (c)		($1,462,980)	($1,462,980)	($1,462,980)	($1,462,980)
24	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 22 through 23		$3,311,681	$3,826,515	$4,268,783	$4,644,107
	Rate Base Calculation:						
25	Cumulative Incremental Capital Included in Rate Base	Line 13		$53,920,323	$53,920,323	$53,920,323	$53,920,323
26	Accumulated Depreciation	-Line 19		($1,075,467)	($3,226,400)	($5,377,333)	($7,528,266)
27	Deferred Tax Reserve	-Line 24		($3,311,681)	($3,826,515)	($4,268,783)	($4,644,107)
28	Year End Rate Base before Deferred Tax Proration	Sum of Lines 25 through 27		$49,533,176	$46,867,408	$44,274,208	$41,747,950
	Revenue Requirement Calculation:						
29	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 28 * Page 13 of 29, Line 16, Col(e); Then =(Prior Year Line 28 + Current Year Line 28) ÷ 2				$45,570,808	$43,011,079
30	Proration Adjustment	Page 12 of 29, Line 41, Column (l)				$18,529	$15,724
31	Average ISR Rate Base after Deferred Tax Proration	Line 30 + Line 31				$45,589,337	$43,026,803
32	Pre-Tax ROR	Page 28 of 29, Line 35				8.23%	8.23%
33	Return and Taxes	Line 31 * Line 32				$3,752,002	$3,541,106
34	Book Depreciation	Line 18				$2,150,933	$2,150,933
35	**Annual Revenue Requirement**	Line 33 + Line 34		**N/A**	**N/A**	**$5,902,936**	**$5,692,039**

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

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

Line No.				Fiscal Year 2020 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 10 of 29, 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 30%, up to December 31, 2019	14.78% × 30% × 75%	2/	3.33%	2026	4.888%	$3,116,380	$46,737,872
11	Bonus Depreciation Rate 0%, after December 31, 2019			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 29, 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 2022 Electric ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2020 Incremental Capital Investment

Line No.				(a) FY22	(b) FY23
	Deferred Tax Subject to Proration				
1	Book Depreciation	Page 10 of 29, Line 18, column (c) & (d)		$2,150,933	$2,150,933
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	Page 11 of 29, Line 6 and Line 7, col (d)		($4,256,970)	($3,938,192)
4	FY 2020 tax (gain)/loss on retirements				
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($2,106,037)	($1,787,258)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($442,268)	($375,324)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction				
9	Cost of Removal				
10	Book/Tax Depreciation Timing Difference at 3/31/2020			$0	
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		$0	
12	Effective Tax Rate			21.00%	
13	Deferred Tax Reserve	Line 11 * Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13		($442,267.80)	($375,324)
15	Net Operating Loss			$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($442,268)	($375,324)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5			
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11			
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18			
20	Total FY 2020 Federal NOL (Utilization)	Docket No. 4915, R. S. 5, Att. 1S, P 10 of 19, Col (a)			
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20			
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20			
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($442,268)	($375,324)
		(j)	(k)	(l)	(m)
	Proration Calculation	Number of Days in Month	Proration Percentage		
26	April	30	91.80%	($33,835)	($28,713)
27	May	31	83.33%	($30,713)	($26,064)
28	June	30	75.14%	($27,692)	($23,500)
29	July	31	66.67%	($24,570)	($20,851)
30	August	31	58.20%	($21,449)	($18,202)
31	September	30	50.00%	($18,428)	($15,639)
32	October	31	41.53%	($15,306)	($12,989)
33	November	30	33.33%	($12,285)	($10,426)
34	December	31	24.86%	($9,164)	($7,777)
35	January	31	16.39%	($6,042)	($5,127)
36	February	29	8.47%	($3,122)	($2,649)
37	March	31	0.00%	$0	$0
38	Total	366		($202,605)	($171,938)
39	Deferred Tax Without Proration	Line 25		($442,268)	($375,324)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 13 of 29, Line 16, Col (e); then = Line 39 * 50%		($221,134)	($187,662)
41	Proration Adjustment	Line 38 - Line 40		$18,529	$15,724

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

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
ISR Additions April 2019 through March 2020

Line No.	Month No.	Month	FY 2021 Plant Additions	In Rates	Not In Rates	Weight for Days	Weighted Average	Weight for Not in Rates
			(a)	(b)	(c) = (a) - (b)	(d)	(e) = (d) * (c)	(f)=(c)/Total(c)
1								
2	1	Apr-19	9,207,833	6,236,917	2,970,917	0.958	2,847,128	3.75%
3	2	May-19	9,207,833	6,236,917	2,970,917	0.875	2,599,552	3.75%
4	3	Jun-19	9,207,833	6,236,917	2,970,917	0.792	2,351,976	3.75%
5	4	Jul-19	9,207,833	6,236,917	2,970,917	0.708	2,104,399	3.75%
6	5	Aug-19	9,207,833	6,236,917	2,970,917	0.625	1,856,823	3.75%
7	6	Sep-19	9,207,833	-	9,207,833	0.542	4,987,576	11.61%
8	7	Oct-19	9,207,833	-	9,207,833	0.458	4,220,257	11.61%
9	8	Nov-19	9,207,833	-	9,207,833	0.375	3,452,938	11.61%
10	9	Dec-19	9,207,833	-	9,207,833	0.292	2,685,618	11.61%
11	10	Jan-20	9,207,833	-	9,207,833	0.208	1,918,299	11.61%
12	11	Feb-20	9,207,833	-	9,207,833	0.125	1,150,979	11.61%
13	12	Mar-20	9,207,833	-	9,207,833	0.042	383,660	11.61%
14		Total	$110,494,000	$31,184,583	$79,309,417		$30,559,205	100.00%
15	**Total September 2020 through March 2021**				**$ 64,454,833**			
16	**FY2021 Weighted Average Incremental Rate Base Percentage**						**38.53%**	

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

The Narragansett Electric Company
d/b/a National Grid
Electric Infrastructure, Safety, and Reliability (ISR) Plan
FY 2022 Revenue Requirement on FY 2021 Forecasted Incremental Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)	Fiscal Year 2023 (c)
	Capital Investment Allowance					
1	*Non-Discretionary Capital*	RIPUC Docket No. 4995, Sec. 5 Revised, Attach. 1R, Page 14		$33,545,000		
	Discretionary Capital					
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	RIPUC Docket No. 4995, Sec. 5 Revised, Attach. 1R, Page 14		$75,949,000	$0	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 21 of 29, Line 4(d)		$109,494,000	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$109,494,000	$0	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (d)		$20,282,977	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$89,211,023	$89,211,023	$89,211,023
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$109,494,000	$0	$0
8	Depreciation Expense	Page 25 of 29, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920		$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$59,587,080	$59,587,080	$59,587,080
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (d)		$11,494,600	$11,494,600	$11,494,600
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$71,081,680**	**$71,081,680**	**$71,081,680**
	Deferred Tax Calculation:					
12	Composite Book Depreciation Rate	Page 23 of 29, Line 3, Col (e)	1/	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:					
14	2021 Spend	Year 1 = Page 15 of 29, Line 22, Column (a), Then = Page 15 of 29, Column (d)		$27,034,837	$7,068,880	$6,538,151
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$27,034,837	$34,103,717	$40,641,868
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,409,534	$2,819,068	$2,819,068
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,409,534	$4,228,602	$7,047,671
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$25,625,303	$29,875,115	$33,594,197
19	Effective Tax Rate			21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$5,381,314	$6,273,774	$7,054,781
21	Add: FY 2021 Federal (NOL) Utilization	Page 21 of 29, Line 15, Col (d)		($6,764,379)	($6,764,379)	($6,764,379)
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21		($1,383,066)	($490,605)	$290,402
	Rate Base Calculation:					
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$71,081,680	$71,081,680	$71,081,680
24	Accumulated Depreciation	-Line 17		($1,409,534)	($4,228,602)	($7,047,671)
25	Deferred Tax Reserve	-Line 22		$1,383,066	$490,605	($290,402)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$71,055,211	$67,343,682	$63,743,607
	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			$69,199,447	$65,543,644
28	Proration Adjustment	Page 17 of 29, Line 41			$41,025	$33,570
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29			$69,240,472	$65,577,214
30	Pre-Tax ROR	Page 28 of 29, Line 35			8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30			$5,698,491	$5,397,005
32	Book Depreciation	Line 16			$2,819,068	$2,819,068
33	Revenue Requirement of Intangible Assets	Page 16 of 29 Line 30 Column (a) ~ (b)			$206,267	$191,858
34	**Annual Revenue Requirement**	**Line 31 + Line 32 + Line 33**		**N/A**	**$8,723,827**	**$8,407,931**

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

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

Line No.				Fiscal Year 2021 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 14 of 29, Line 3		$109,494,000
2	Capital Repairs Deduction Rate	Per Tax Department	1/	10.57%
3	Capital Repairs Deduction	Line 1 * Line 2		$11,573,516
	Bonus Depreciation			
4	Plant Additions	Line 1		$109,494,000
5	Plant Additions			$0
6	Less Capital Repairs Deduction	Line 3		$11,573,516
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$97,920,484
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 * 75% * 0%		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		$109,494,000
15	Less Capital Repairs Deduction	Line 3		$11,573,516
16	Less Bonus Depreciation	Line 13		$0
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$97,920,484
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
19	Remaining Tax Depreciation	Line 17 * Line 18		$3,672,018
20	FY21 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$294,703
21	Cost of Removal	Page 14 of 29, Line 10		$11,494,600
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$27,034,837

20 Year MACRS Depreciation

(b)	(c)	(d)	(e)
MACRS basis:	Line 17	$97,920,484	
		Annual	Cumulative
Fiscal Year			
2021	3.750%	$3,672,018	$27,034,837
2022	7.219%	$7,068,880	$34,103,717
2023	6.677%	$6,538,151	$40,641,867
2024	6.177%	$6,048,548	$46,690,416
2025	5.713%	$5,594,197	$52,284,613
2026	5.285%	$5,175,098	$57,459,711
2027	4.888%	$4,786,353	$62,246,064
2028	4.522%	$4,427,964	$66,674,028
2029	4.462%	$4,369,212	$71,043,240
2030	4.461%	$4,368,233	$75,411,473
2031	4.462%	$4,369,212	$79,780,685
2032	4.461%	$4,368,233	$84,148,918
2033	4.462%	$4,369,212	$88,518,130
2034	4.461%	$4,368,233	$92,886,362
2035	4.462%	$4,369,212	$97,255,574
2036	4.461%	$4,368,233	$101,623,807
2037	4.462%	$4,369,212	$105,993,019
2038	4.461%	$4,368,233	$110,361,252
2039	4.462%	$4,369,212	$114,730,464
2040	4.461%	$4,368,233	$119,098,697
2041	2.231%	$2,184,606	$121,283,303
	100.00%	$97,920,484	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
FY 2022 Revenue Requirement on FY 2021 Intangible Investment

Line No.		Reference	FY 21 (a)	FY 22 (b)	FY 23 (c)
	Capital Investment				
1	Start of Rev. Req. Period		04/01/20	04/01/21	04/01/22
2	End of Rev. Req. Period		03/31/21	03/31/22	03/31/23
3	Investment Name		Volt-Var Optimization IS	Volt-Var Optimization IS	Volt-Var Optimization IS
4	Work Order				
5	Total Spend	Section 2, Chart 10, Column 2 note	$1,000,000	$1,000,000	$1,000,000
6	In ServiceDate	Estimated in-service date	09/30/20	09/30/20	09/30/20
7	Book AmortizationPeriod	Estimated useful life	84	84	84
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$0	$928,571	$785,714
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$928,571	$785,714	$642,857
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$464,286	$857,143	$714,286
	Deferred Tax Calculation:				
11	Tax Amortization Period	Page 9 of 29	36	36	36
12	Tax Expensing	Per Tax Department	$0	$0	$0
13	Tax Bonus Rate	Per Tax Department	0%	0%	0%
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 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%)	$0	$333,300	$777,800
16	Ending Acc. Tax Balance	(L. 5 - L. 12- L.14) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$333,300	$777,800	$925,900
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$166,650	$555,550	$851,850
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$0	$71,429	$214,286
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$71,429	$214,286	$357,143
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$35,714	$142,857	$285,714
21	Average Book / Tax Timer	Line 17 - Line 20	$130,936	$412,693	$566,136
22	Effective Tax Rate		21%	21%	21%
23	Deferred Tax Reserve	Line 21 × Line 22	$27,497	$86,666	$118,889
	Rate Base Calculation:				
24	Average Book Balance	Line 10	$464,286	$857,143	$714,286
25	Deferred Tax Reserve	Line 23	$27,497	$86,666	$118,889
26	Average Rate Base	Line 24 - Line 25	$436,789	$770,477	$595,397
	Revenue Requirement Calculation:				
27	Pre-Tax ROR	year 1 = Page 28 of 29, Line 27, column (e)×7÷12 Then = Page 28 of 29, Line 27(e)	8.23%	8.23%	8.23%
28	Return and Taxes	Line 26 × Line 27	$35,948	$63,410	$49,001
29	Book Depreciation	Line 9 - Line 8	$71,429	$142,857	$142,857
30	Annual Revenue Requirement	Line 28 + Line 29	$107,376	$206,267	$191,858

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2021 Incremental Capital Investment

Line No.	Deferred Tax Subject to Proration			(a) FY22	(b) FY23
1	Book Depreciation	Page 14 of 29, Line 16 + (Page 16 of 29, Line 19-Line 18)		$2,961,925	$2,961,925
2	Bonus Depreciation			$0	$0
3	Remaining MACRS Tax Depreciation	- Page 15 of 29, column (d) - (Page 16 of 29, Line 16- Line 15)		($7,513,380)	($6,686,251)
4	FY 2021 tax (gain)/loss on retirements				
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($4,551,454)	($3,724,325)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($955,805)	($782,108)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	- Page 15 of 29, Line 3			
9	Cost of Removal	- Page 15 of 29, Line 21			
10	Book/Tax Depreciation Timing Difference at 3/31/2021				
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10			
12	Effective Tax Rate				
13	Deferred Tax Reserve	Line 11 * Line 12			
14	Total Deferred Tax Reserve	Line 7 + Line 13		($955,805)	($782,108)
15	Net Operating Loss	- Page 14 of 29, Line 21		$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($955,805)	($782,108)
	Allocation of FY 2020 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5			
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11			
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18			
20	Total FY 2021 Federal NOL (Utilization)	- Page 14 of 29, Line 21 / 21%			
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20			
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20			
23	Effective Tax Rate				
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23			
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($955,805)	($782,108)
		(j)	(k)	(l)	(m)
	Proration Calculation	Number of Days in Month	Proration Percentage		
26	April	30	91.78%	($73,104)	($59,819)
27	May	31	83.29%	($66,339)	($54,283)
28	June	30	75.07%	($59,792)	($48,926)
29	July	31	66.58%	($53,028)	($43,391)
30	August	31	58.08%	($46,263)	($37,855)
31	September	30	49.86%	($39,716)	($32,499)
32	October	31	41.37%	($32,951)	($26,963)
33	November	30	33.15%	($26,405)	($21,606)
34	December	31	24.66%	($19,640)	($16,071)
35	January	31	16.16%	($12,875)	($10,535)
36	February	28	8.49%	($6,765)	($5,535)
37	March	31	0.00%	$0	$0
38	Total	365		($436,877)	($357,484)
39	Deferred Tax Without Proration	Line 25		($955,805)	($782,108)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($477,903)	($391,054)
41	Proration Adjustment	Line 38 - Line 40		$41,025	$33,570

Column Notes:

(k) Sum of remaining days in the year (Col (j)) ÷ 365

(l) & (m) Current Year Line 25 ÷ 12 × Current Month Col (k)

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

Line No.				Fiscal Year 2022 (a)	Fiscal Year 2023 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*	Page 29 of 29, Line 1		$42,882,000	
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (non-intangible)	Page 29 of 29, Line 13		$56,630,000	$0
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 21 of 29, Line 4(e)		$99,512,000	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$99,512,000	$0
5	Retirements	Page 21 of 29 , Line 10 ,Col (e)		$13,258,585	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$86,253,415	$86,253,415
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$99,512,000	$0
8	Depreciation Expense	Page 25 of 29, Line 62, Col (d)		$49,906,920	
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$49,605,080	$49,605,080
10	Cost of Removal	Page 21 of 29 , Line 7 ,Col (e)		$14,514,417	$14,514,417
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$64,119,496**	**$64,119,496**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	Page 23 of 29, Line 3, Col (e)	1/	3.16%	3.16%
13	Vintage Year Tax Depreciation:				
14	2022 Spend	Year 1 = Page 19 of 29, Line 21, Column (a), Then = Page 19 of 29, Column (d)		$28,541,167	$6,572,432
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$28,541,167	$35,113,599
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,362,804	$2,725,608
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,362,804	$4,088,412
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$27,178,363	$31,025,187
19	Effective Tax Rate			21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$5,707,456	$6,515,289
21	Add: FY 2022 Federal (NOL) Utilization	Page 21 of 29, Line 15, Col (e)		$1,703,802	$1,703,802
22	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 21		$7,411,258	$8,219,091
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$64,119,496	$64,119,496
24	Accumulated Depreciation	-Line 17		($1,362,804)	($4,088,412)
25	Deferred Tax Reserve	-Line 22		($7,411,258)	($8,219,091)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$55,345,434	$51,811,993
	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		$27,672,717	$53,578,713
28	Proration Adjustment	Page 20 of 29, Line 41		$49,106	$34,674
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29		$27,721,823	$53,613,388
30	Pre-Tax ROR	Page 28 of 29, Line 35		8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30		$2,281,506	$4,412,382
32	Book Depreciation	Line 16		$1,362,804	$2,725,608
33	**Annual Revenue Requirement**	**Line 31 + Line 32**		**$3,644,310**	**$7,137,990**

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

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

Line No.				Fiscal Year 2022 (a)
	Capital Repairs Deduction			
1	Plant Additions	Page 18 of 29, Line 3		$99,512,000
2	Capital Repairs Deduction Rate	Per Tax Department	1/	8.51%
3	Capital Repairs Deduction	Line 1 * Line 2		$8,468,471
	Bonus Depreciation			
4	Plant Additions	Line 1		$99,512,000
5	Plant Additions			$0
6	Less Capital Repairs Deduction	Line 3		$8,468,471
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$91,043,529
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	at 0%		0.00%
11	Total Bonus Depreciation Rate	Line 10		0.00%
12	Bonus Depreciation	Line 9 * Line 11		$0
	Remaining Tax Depreciation			
13	Plant Additions	Line 1		$99,512,000
14	Less Capital Repairs Deduction	Line 3		$8,468,471
15	Less Bonus Depreciation	Line 12		$0
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$91,043,529
17	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
18	Remaining Tax Depreciation	Line 16 * Line 17		$3,414,132
19	FY22 (Gain)/Loss incurred due to retirements	Per Tax Department	2/	$2,144,147
20	Cost of Removal	Page 18 of 29, Line 10		$14,514,417
21	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19, and 20		$28,541,167

20 Year MACRS Depreciation

MACRS basis: Line 16 $91,043,529

(b) Fiscal Year	(c)	(d) Annual	(e) Cumulative
2022	3.750%	$3,414,132	$28,541,167
2023	7.219%	$6,572,432	$35,113,599
2024	6.677%	$6,078,976	$41,192,575
2025	6.177%	$5,623,759	$46,816,334
2026	5.713%	$5,201,317	$52,017,651
2027	5.285%	$4,811,651	$56,829,302
2028	4.888%	$4,450,208	$61,279,509
2029	4.522%	$4,116,988	$65,396,498
2030	4.462%	$4,062,362	$69,458,860
2031	4.461%	$4,061,452	$73,520,312
2032	4.462%	$4,062,362	$77,582,674
2033	4.461%	$4,061,452	$81,644,126
2034	4.462%	$4,062,362	$85,706,488
2035	4.461%	$4,061,452	$89,767,940
2036	4.462%	$4,062,362	$93,830,302
2037	4.461%	$4,061,452	$97,891,754
2038	4.462%	$4,062,362	$101,954,116
2039	4.461%	$4,061,452	$106,015,568
2040	4.462%	$4,062,362	$110,077,930
2041	4.461%	$4,061,452	$114,139,382
2042	2.231%	$2,031,181	$116,170,563
	100.00%	$91,043,529	

1/ Per Tax Department
2/ Per Tax Department

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2022 Incremental Capital Investment

Line No.	Deferred Tax Subject to Proration			(a) FY22	(b) FY23
1	Book Depreciation	Page 18 of 29, Line 16		$1,362,804	$2,725,608
2	Bonus Depreciation	- Page 19 of 29, Line 12		$0	$0
3	Remaining MACRS Tax Depreciation	- Page 19 of 29, column (d)		($3,414,132)	($6,572,432)
4	FY 2021 tax (gain)/loss on retirements	- Page 19 of 29, Line 19		($2,144,147)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($4,195,475)	($3,846,824)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($881,050)	($807,833)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	- Page 19 of 29, Line 3		($8,468,471)	
9	Cost of Removal	- Page 19 of 29, Line 20		($14,514,417)	
10	Book/Tax Depreciation Timing Difference at 3/31/2022			$0	
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		($22,982,888)	
12	Effective Tax Rate			21.00%	
13	Deferred Tax Reserve	Line 11 * Line 12		($4,826,406)	
14	Total Deferred Tax Reserve	Line 7 + Line 13		($5,707,456)	($807,833)
15	Net Operating Loss	- Page 18 of 29, Line 21		($1,703,802)	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		($7,411,258)	($807,833)
	Allocation of FY 2020 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5		($4,195,475)	
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		($22,982,888)	
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($27,178,363)	
20	Total FY 2021 Federal NOL (Utilization)	- Page 18 of 29, Line 21 / 21%		($8,113,343)	
21	Allocated FY 2022 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20		($6,860,901)	
22	Allocated FY 2022 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20		($1,252,442)	
23	Effective Tax Rate			21.00%	
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23		($263,013)	
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		($1,144,063)	($807,833)
		(j)	(k)	(l)	(m)
	Proration Calculation	Number of Days in Month	Proration Percentage		
26	April	30	91.78%	($87,502.51)	($61,786)
27	May	31	83.29%	($79,405.27)	($56,069)
28	June	30	75.07%	($71,569.22)	($50,536)
29	July	31	66.58%	($63,471.97)	($44,818)
30	August	31	58.08%	($55,374.72)	($39,101)
31	September	30	49.86%	($47,538.68)	($33,567)
32	October	31	41.37%	($39,441.43)	($27,850)
33	November	30	33.15%	($31,605.39)	($22,317)
34	December	31	24.66%	($23,508.14)	($16,599)
35	January	31	16.16%	($15,410.89)	($10,882)
36	February	28	8.49%	($8,097.25)	($5,718)
37	March	31	0.00%	$0.00	$0
38	Total	365		($522,925)	($369,242)
39	Deferred Tax Without Proration	Line 25		($1,144,063)	($807,833)
40	Average Deferred Tax without Proration	Line 39 × 0.5		($572,031)	($403,917)
41	Proration Adjustment	Line 38 - Line 40		$49,106	$34,674

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

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
FY 2018 - 2022 Incremental Capital Investment Summary

Line No.			Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)
	Capital Investment						
1	ISR - Eligible Capital Investment	Col (a) (b) & (c) = FY20 Docket 4915, Att MAL-1, P15, L1 Col (d) = FY21 Docket 4955, Att MAL-1, P18, L1; Col (e)= Section 2, Chart 19, Col 2	$92,659,654	$111,243,061	$103,267,720	$110,494,000	$99,512,000
2	Intangible Assets included in Total Allowed Discretionary Capital	Col (a) (b) & (c) = FY20 Docket 4915, Att MAL-1, P15, L2; Col (d) = FY 2021 ISR Docket No. 4995, Att. MAL-1,Page 18 of 25, L. 2, C.(d)	$0	$3,460,626	$0	$1,000,000	$0
3	ISR - Eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P5, L1, Col (a) = Col(a)+Col(b); Col(b)=Col(c)+Col(d); Col(c)=Col(e), Col(d)=Col(j)+Col(k)	$74,843,000	$74,843,000	$31,184,583	$0	$0
4	Incremental ISR Capital Investment (non-intangible)	Line 1 - Line 2 - Line 3	$17,816,654	$32,939,435	$72,083,137	$109,494,000	$99,512,000
	Cost of Removal						
5	ISR - Eligible Cost of Removal	Col (a) (b) & (c) = FY20 Docket 4915, Att MAL-1, P15, L5; Col (d)= FY 2021 Docket 4995, Att MAL-1, P18, L5; Col(e)= Section 2, Chart 10, Column 3	$9,979,698	$7,949,082	$14,387,482	$11,700,000	$14,600,000
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; Col (d) = L39×5÷12+L60×7÷12; Col (e)= L60×5÷12	$8,259,707	$7,848,009	$3,437,925	$205,400	$85,583
7	Incremental Cost of Removal	Line 5 - Line 6	$1,719,991	$101,073	$10,949,557	$11,494,600	$14,514,417
	Retirements						
8	ISR - Eligible Retirements/Actual	Col (a) (b) & (c) = FY20 Docket 4915, Att MAL-1, P15, L8; Col (d)= FY 2021 Docket 4995, Att MAL-1, P18, L8; Col (e)= Line 1(e)* Past 3 Year Average Retirement Rate	$15,206,748	$12,015,754	$13,944,441	$20,876,177	$13,505,751
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; Col (d) = L40×5÷12+L61×7÷12; Col (e)= L61×5÷12	$20,451,820	$22,665,233	$9,928,809	$593,200	$247,167
10	Incremental Retirements	Line 8 - Line 9	($5,245,072)	($10,649,479)	$4,015,632	$20,282,977	$13,258,585
	Net NOL Position						
11	ISR - (NOL)/Utilization	Col (a) (b) & (c) = FY20 Docket 4915, Att MAL-1, P15, L11; Col (d) & (e)= Per Tax Department	($4,571,409)	$1,506,783	$0	$0	$8,772,838
12	less: (NOL)/Utilization recovered in transmission rates	Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 11	($1,572,911)	$515,161	$0	$0	$2,983,755
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 22 of 29, Line 11	($2,998,499)	$991,622	$0	$0	$5,789,083
14	(NOL)/Utilization in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P. 12: Col (c)= L39×7÷12; Col (d) = L39×7÷12+L49×5÷12; Col (e) = L49×7÷12	$0	$0	$1,462,980	$6,764,379	$4,085,281
15	Incremental (NOL)/Utilization	Line 13 - Line 14	($2,998,499)	$991,622	($1,462,980)	($6,764,379)	$1,703,802

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Electric ISR Revenue Requirement Plan
Deferred Income Tax ("DIT") Provisions and Net Operating Losses ("NOL")

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			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	12 Mths Aug 31 2022
1	Total Base Rate Plant DIT Provision		$18,265,666				$2,580,654	$5,847,765	$4,355,117	$707,056	$3,826,291	$0
2	Excess DIT Amortization								($3,074,665)	($3,074,665)	($3,074,665)	$0
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
3	Total Base Rate Plant DIT Provision							$10,558,267	$3,183,498.68	($847,583.55)	($548,055)	$313,177
4	Incremental FY 18	$4,261,399	$4,223,434	$4,181,310	$4,130,879	$4,072,741		$4,261,399	($37,965)	($42,125)	($50,431)	($58,138)
5	Incremental FY 19	$0	$2,128,597	$2,305,665	$2,485,863	$2,504,666			$2,128,597	$177,068	$180,198	$18,803
6	Incremental FY 20			$4,774,661	$5,289,496	$5,731,763				$4,774,661	$514,834	$442,268
7	Incremental FY 21				$5,381,314	$6,273,774					$5,381,314	$892,460
8	Incremental FY 22					$5,707,456						$5,707,456
9	TOTAL Plant DIT Provision	$4,261,399	$6,352,031	$11,261,636	$17,287,551	$24,290,401		$14,819,666	$5,274,131	$4,062,021	$5,477,860	$7,316,027
10	Distribution-related NOL							$2,998,499	($991,622)	$0	$0	($5,789,083)
11	Lesser of Distribution-related NOL or DIT Provision							$2,998,499	($991,622)	$0	$0	($5,789,083)

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(f) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 3
1(g) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 7
1(h) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 11 of 20, Line 50
1(i) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 12 of 20, Line 41
1(j) RIPUC Docket Nos. 4770/4780, Compliance, Revised Rebuttal Attachment 1, Schedule 11-ELEC, Page 12 of 20, Line 51
1(k) RIPUC Docket Nos. 4770/4780 third rate year ends at Aug 31, 2021
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)~(e) Cumulative DIT per vintage year ISR revenue requirement calculations (P.2, L.20+L.22, Cols (a) through (e))
5(b)~(e) Cumulative DIT per vintage year ISR revenue requirement calculations (P.5, L.20+ P.8, L.23, Cols (a) through (d))
6(c)~(e) Cumulative DIT per vintage year ISR revenue requirement calculations (P.10, L.20, Cols (a) through (c))
7(d)~(e) Cumulative DIT per vintage year ISR revenue requirement calculations (P.13, L.20(a) and (b))
8(e) Cumulative DIT per vintage year ISR revenue requirement calculations (P.17, L.20(a))
4(g)~8(k) Year over year change in cumulative DIT shown in Cols (a) through (e)
9 Sum of Lines 3 through 6
10 Page 21 of 29, Line 13
11 Lesser of Line 9 or Line 10

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 Syster	$ 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 Streetlighting	$ 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. 4770

		Adjusted Plant Balance (d)	Average Rate (e)=(f)/(g)	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
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%

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket Nos. 4770/4780
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, Column (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, Column (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

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

The Narragansett Electric Company
d/b/a National Grid
FY 2022 ISR Property Tax Recovery Adjustment
($000s)

Line	Effective Tax Rate Calculation	(a) End of FY 2018	(b) ISR Additions	(c) Non-ISR Add's	(d) Total Add's	(e) Bk Depr (1)	(f) Retirements	(g) COR	(h) 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	$110,494	$3,137	$113,631		($20,876)		$1,883,480
12	Accumulated Depr	$730,328				$57,266	($20,876)	($11,700)	$755,018
13	Net Plant	$1,060,397							$1,128,462
14	Property Tax Expense	$32,568							$36,460
15	Effective Prop tax Rate	3.07%							3.23%
	Effective Tax Rate Calculation	**End of FY 2021**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2022**
16	Plant In Service	$1,883,480	$99,512	$4,244	$103,756		($13,506)		$1,973,730
17	Accumulated Depr	$755,018				$60,015	($13,506)	($14,600)	$786,927
18	Net Plant	$1,128,462							$1,186,803
19	Property Tax Expense	$36,460							$36,447
20	Effective Prop tax Rate	3.23%							3.07%

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

The Narragansett Electric Company
d/b/a National Grid
FY 2022 ISR Property Tax Recovery Adjustment (continued)
($000s)

	Property Tax Recovery Calculation	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Cumulative Increm. ISR Prop. Tax for FY2020				Cumulative Increm. ISR Prop. Tax for FY2021				Cumulative Increm. ISR Prop. Tax for FY2022		
38	Incremental ISR Additions		$72,083				$110,494				$99,512	
39	Book Depreciation: base allowance on ISR eligible plant		$0				$0				($29,112)	
40	Book Depreciation: current year ISR additions		($1,075)				($1,481)				($1,363)	
41	COR		$10,950				$11,495				$14,514	
42	Net Plant Additions		$81,957				$120,508				$83,551	
43	RY Effective Tax Rate		3.38%				3.58%				3.66%	
44	ISR Year Effective Tax Rate	3.07%				3.23%				3.07%		
45	RY Effective Tax Rate	3.38%	-0.31%			3.58%	-0.35%			3.66%	-0.59%	
46	RY Net Plant times Rate Difference	$902,404	-0.31%	($2,816)		$853,576	* -0.35%	($2,954)		$833,223	* -0.59%	($4,941)
47	Non-ISR plant times rate difference	($2,269)	-0.31%	$7		($4,269)	* -0.35%	$15		($6,269)	* -0.59%	$37
48	FY 2018 Net Incremental times rate difference	$17,664	3.07%	$543		$16,935	* 3.23%	$547		$16,207	* 3.07%	$498
49	FY 2019 Net Incremental times rate difference	$33,630	3.07%	$1,033		$31,759	* 3.23%	$1,026		$29,887	* 3.07%	$918
50	FY 2020 Net Incremental times rate difference	$81,957	3.07%	$2,517		$79,806	* 3.23%	$2,578		$77,655	* 3.07%	$2,385
51	FY 2021 Net Adds times rate difference					$120,508	* 3.23%	$3,894		$117,546	* 3.07%	$3,610
52	FY 2022 Net Adds times rate difference									$83,551	* 3.07%	$2,566
53	Total ISR Property Tax Recovery			$1,284				$5,106				$5,072

Line Notes

1(a) - 10(h)	Per Docket No. 4915, FY2020 Rec, Attachment MAL-1, Page 20, Line 1(a)~Line 10(h)
11(a) - 15(a)	=6(h) ~ 10(h)
11(b)	Page 21 of 29, 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)	Sum of L11 C(a), L11 C(d), L11 C(f)
12(e)	[Docket 4770, C. Att. 2, Sch 6-ELEC, P2: L (16(b)+ L17(b)) × 5/12+ L (37(b) + 38(b)) × 7/12] +((Page 2 of 29, L 6(a) + Page 5 of 29, L 6(a)+Page 10 of 29, L8(a)) × 0.0316+,Page 8 of 29, L29(c))/1000 + (Page 14 of 29, L6(a) × 0.0316× 0.5 +,Page 16 of 29, L29(a))/1000
12(g)	Page 21 of 29, Line 8 , Column (d)/1000
12(h)	Sum of L12 C(a), L12 C(e), L12 C(f), L12 C(g)
13(h)	11(h)-12(h)
14(h)	13(h)×15(h)
15(h)	5(h)
16(a) - 20(a)	Per Line 11(h) ~ 15(h)
16(b)	Page 21 of 29 , Line 1 ,Col (e)÷1000
16(c)	Estimated based on FY2020 actual non-ISR addition
16(d)	Line 16(b) + Line 16(c)
16(f)	Page 21 of 29 , Line 8 ,Col (e)÷1000
16(h)	Line 16(a) + (d) + (f)
17(e)	Docket 4770, C. Att. 2, Sch 6-ELEC, P2: (L37(b) + L38(b)) +((Page 2 of 29, L 6(a) + Page 5 of 29, L 6(a)+Page 10 of 29, L8(a)+Page 14 of 29, L6(a)) × 0.0316+Page 8 of 2929(d)+Page 16 of 29, L29(b))/1000 + (L1(c)+L6(c)+L11(c))×0.0301+Page 18 of 29, L6(a) × 0.0316× 0.5)/1000+L16(c)×0.5×0.0301
17(f)	=17(f)
17(g)	Page 21 of 29 , Line 5 ,Col (e)÷1000
17(h)	Line 17(a) + (e) + (f) + (g)
18(h)	Line 16(h) - 17(h)
19(h)	Line (h) × 20(h)
20(h)	Estimated based on FY2020 actual property rate

Line Notes

22(a) - 37(g)	Docket No. 4915 Attachment MAL-1, Page 20 of 23, 11(a) to 27(g)
22(i) - 37(k)	Docket No. 4915 Attachment MAL-1, Page 21 of 23, 28(a) to 44(c)
38(a) - 53(c)	Docket No. 4915 Attachment MAL-1, Page 21 of 23, 28(e) to 44(g)
38(f)	(Page 14 of 29, Line 3+Page 16 of 29, Line 5)÷1000
38(j)	Page 18 of 29, Line 3÷1000
39(f)	FY21 depreciation is reflected in the NBV at 46(e)
39(j)	- (Page 25 of 29, Line 62(d) ×7÷12)÷1000
40(f)	(- Page 14 of 29, Line 16(a) - Page 16 of 29, Line 29(a))÷1000
40(j)	- Page 18 of 29, Line 16(a)÷1000
41(f)	Page 14 of 29, Line 10(a)÷1000
41(j)	Page 18 of 29, Line 10(a)÷1000
42(f)	Sum of Lines 38(f) through 41(f)
42(j)	Sum of Lines 38(j) through 41(j)
43(f)	Docket No. 4770, R. Rebuttal Att. 1, Sch 7-ELEC, P.2, L 3 (e) ÷ 46(e)
43(j)	Docket No. 4770, R. Rebuttal Att. 1, Sch 7-ELEC, P.2, L 3 (e) ÷ 46(i)
44(e)	=15(h)
44(i)	=20(h)
45(e)	=43(f)
45(f)	44(e) -45(e)
45(i)	=43(j)
45(j)	44(i)-45(i)
46(e)	Docket No. 4770, R. Rebuttal Att. 1, Sch 6-E, P2, ((L30 - L41)*5/12+ (L51-L62)*7/12]/1000
46(g)	46(e) ×45(f)
46(i)	Docket No. 4770, R. Rebuttal Att. 1, Sch 6-E, P2, (L51-L62)/1000]

Line Notes

46(k)	46(i)×45(j)
47(e)	- Docket No. 4770, R. Rebuttal Att. 1, Sch 11-ELEC, P.5, L.8(h) + L.8(j)
47(g)	47(e) ×45(f)
47(i)	- Docket No. 4770, R. Rebuttal Att. 1, Sch 11-ELEC, P.5, L.8(h) + L.8(j) + L.8(l)
47(k)	47(i)×44(i)
48(e)	Line 48(a) - Page 2 of 29, Line 16(d))÷1000
48(g)	=48(e) ×44(e)
48(i)	Line 48(e) - Page 2 of 29, Line 16(e))÷1000
48(k)	48(i)×44(i)
49(e)	Line 49(a) - Page 5 of 29, Line 16(c))÷1000
49(g)	=49(e) ×44(e)
49(i)	Line 49(e) - Page 5 of 29, Line 16(d))÷1000
49(k)	49(i)×44(i)
50(e)	Line 50(a) - Page 10 of 29, Line 18(b))÷1000
50(g)	=50(e) ×44(e)
50(i)	Line 50(e) - Page 10 of 29, Line 18(c))÷1000
50(k)	50(i)×44(i)
51(e)	=42(f)
51(g)	=51(e) ×44(e)
51(i)	=51(j) - (Page 14 of 29, Line 16(b) + Page 16 of 29, Line 29(b))÷1000
51(k)	51(i)×44(i)
52(i)	=42(j)
52(k)	52(i)×45(j)
53(g)	Sum of 46(g) through (g)
53(k)	Sum of 46(k) through 52(k)

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

The Narragansett Electric Company
d/b/a National Grid
FY 2022 Incremental Capital Investment

Line No.			Fiscal Year 2022 (a)	In Base Rates Included In Docket No. 4770 (b)	Amount to be Included in FY 2021 ISR (c) = (a) - (b)
	Non Discretionary Capital				
1	FY 2022 Proposed Non-Discretionary Capital Additions	Column (a) Section 2, Chart 19, Col 2, Column (b) - Docket No. 4770, Schedule 11-ELEC, Page 5 of 20, Line 5, Column (k).	**$42,882,000**	**$0**	$42,882,000
	Discretionary Capital				
2	Cumulative FY 2021 Discretionary Capital ADDITIONS	Docket 4915 + Docket 4995	$467,828,667		
3	FY 2022 Discretionary Capital ADDITIONS	Section 2, Chart 19, Col 2	$56,630,000		
4	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3	$524,458,667		
5	Cumulative FY 2021 Discretionary Capital SPENDING	Docket 4915 + Docket 4995	$506,479,859		
6	FY 2022 Discretionary Capital SPENDING	Section 2, Chart 19, Col 1	$60,165,000		
7	Cumulative Actual Discretionary Capital Spending	Line 5 + Line 6	$566,644,859		
8	Cumulative FY 2021 Approved Discretionary Capital SPENDING	Docket 4915 + Docket 4995	$490,326,536		
9	FY 2022 Approved Discretionary Capital SPENDING	Section 2, Chart 19, Col 1	$60,165,000		
10	Cumulative Actual Approved Discretionary Capital Spending	Line 8 + Line 9	$550,491,536		
11	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 4, Line 7, or Line 10	$524,458,667		
12	Prior Year Cumulative Allowed Discretionary Capital Included in Rate Base	Docket No. 4915 -ISR Plan Reconciliation	$467,828,667		
13	Total Allowed Discretionary Capital Included in Rate Base Current Year	Line 11 - Line 12	**$56,630,000**	**$0**	**$56,630,000**
14	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 13	**$99,512,000**	**$0**	**$99,512,000**
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			**$99,512,000**

Section 6
Rate Design

Section 6

Rate Design
FY 2022 Electric ISR Plan

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors Calculations - Summary
Summary of Proposed Factors
(for the 12 months beginning April 1, 2021)

		Residential A-16 / A-60 (a)	Small C&I C-06 (b)	General C&I G-02 (c)	Large Demand B-32 (d)	Large Demand G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	O&M Factor per kWh	$0.00224	$0.00215	$0.00179	$0.00093	$0.00093	$0.01142	$0.00031
(2)	O&M Factor per kW	n/a	n/a	n/a	$0.05	n/a	n/a	n/a
(3)	CapEx kWh Charge	$0.00598	$0.00490	n/a	n/a	n/a	$0.00693	$0.00044
(4)	CapEx kW Charge	n/a	n/a	$1.45	$1.46	$1.46	n/a	n/a
(5)	Back-Up Service CapEx kW Charge	n/a	n/a	n/a	$0.14	n/a	n/a	n/a

(1) Page 2, Line (6); Column (d) applicable to supplemental kWh deliveries only
(2) Page 4, Column (a), Line (4), applicable to backup service only
(3) Page 3, Line (6)
(4) Columns (c), (d), and (e) per Page 3, Line (8); Column (d) applicable to supplemental service only
(5) Page 4, Column (a), Line (6), applicable to backup service only

The Narragansett Electric Company
FY22 Proposed Operations & Maintenance Factors
(for the 12 months beginning April 1, 2021)

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B-32 / G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	FY2022 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$11,983,000						
(2)	Operating & Maintenance Expense - Rate Year Allowance ($000s)	$44,205	$22,620	$4,919	$7,563	$7,045	$2,036	$22
(3)	Percentage of Total	100.00%	51.17%	11.13%	17.11%	15.94%	4.61%	0.05%
(4)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$11,983,000	$6,131,783	$1,333,432	$2,050,162	$1,909,744	$551,915	$5,964
(5)	Forecasted kWh - April 2021 through March 2022	6,604,502,902	2,733,527,872	617,923,988	1,141,324,260	2,044,693,944	48,325,850	18,706,988
(6)	Proposed Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00224	$0.00215	$0.00179	$0.00093	$0.01142	$0.00031

(1) per Section 5: Attachment 1, page 1, line (4) column (b)
(2) per RIPUC 4770, Compliance Attachment 6, (Schedule 1B), page 3, line 88
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places

The Narragansett Electric Company
FY22 Proposed CapEx Factors
(for the 12 months beginning April 1, 2021)

		Total (a)	Residential A-16 / A60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	Large Demand B-32 / G-32 (e)	Lighting S-05 / S-06 S-10 / S-14 (f)	Propulsion X-01 (g)
(1)	FY2022 Capital Investment Component of Revenue Requirement	$29,460,447						
(2)	Total Rate Base ($000s)	$729,511	$404,995	$75,009	$117,155	$123,849	$8,296	$208
(3)	Percentage of Total	100.00%	55.52%	10.28%	16.06%	16.98%	1.14%	0.03%
(4)	Allocated Revenue Requirement	$29,460,447	$16,355,236	$3,029,140	$4,731,175	$5,001,500	$335,008	$8,388
(5)	Forecasted kWh - April 2021 through March 2022	6,604,502,902	2,733,527,872	617,923,988	1,141,324,260	2,044,693,944	48,325,850	18,706,988
(6)	Proposed CapEx Factor - kWh charge		$0.00598	$0.00490	n/a	n/a	$0.00693	$0.00044
(7)	Forecasted kW - April 2021 through March 2022				3,252,453	3,425,278		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$1.45	$1.46	n/a	n/a

(1) per Section 5: Attachment 1, page 1, Line (13), Column (b)
(2) RIPUC 4770, Compliance Attachment 6, (Schedule 1A), page 1, Line 9
(3) Line (2), Columns (b) through (g) ÷ Line (2) Total
(4) Line (1) x Line (3)
(5) per Company forecasts
(6) For non demand-based rate classes, Line (4) ÷ Line (5), truncated to 5 decimal places
(7) per Company forecasts
(8) For demand-based rate classes, Line (4) ÷ Line (7), truncated to 2 decimal places
Note: charges apply to kW>10 for rate class G-02 and kW>200 for rate class B-32/G-32

The Narragansett Electric Company
Calculation of Operations & Maintenance and CapEx Factors
and Base Distribution Charge for Back-up Service Rates

		Large Demand B-32 (a)
	Operations & Maintenance Factors	
(1)	Allocated Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$1,909,744
(2)	Forecasted kW - April 2021 through March 2022	3,425,278
(3)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW	$0.55
(4)	Proposed Discounted O&M kW Factor Charge effective 4/1/2021	$0.05
	CapEx Factors	
(5)	Proposed CapEx kW Factor Charge effective 4/01/2021	$1.46
(6)	Proposed Discounted CapEx kW Factor Charge effective 4/1/2021	$0.14

(1) Page 2, Line (4), Column (e)
(2) per Company forecasts
(3) Line (1) ÷ Line (2), truncated to 2 decimal places
(4) Line (3) x .10, truncated to two decimal places
(5) Page 3, Line (8), Column (e)
(6) Line (5) x .10, truncated to two decimal places

Section 7

Bill Impacts
FY 2022 Electric ISR Plan

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

	Rates Effective October 1, 2020				Proposed Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	of Customers
(a)	(b)	(c)	(d)	(e) = (a) + (b) + (c)	(f)	(g)	(h)	(i) = (f) + (g) + (h)	(j) = (f) - (b)	(k) = (g) - (c)	(l) = (h) - (d)	(m) = (j) + (k) + (l)	(n) = (j) / (e)	(o) = (g) / (e)	(p) = (h) / (e)	(q) = (m) / (e)	(r)
150	$25.79	$15.56	$1.72	$43.07	$26.11	$15.56	$1.74	$43.41	$0.32	$0.00	$0.02	$0.34	0.7%	0.0%	0.0%	0.8%	30.1%
300	$42.63	$31.11	$3.07	$76.81	$43.27	$31.11	$3.10	$77.48	$0.64	$0.00	$0.03	$0.67	0.8%	0.0%	0.0%	0.9%	12.9%
400	$53.85	$41.48	$3.97	$99.30	$54.70	$41.48	$4.01	$100.19	$0.85	$0.00	$0.04	$0.89	0.9%	0.0%	0.0%	0.9%	11.6%
500	$65.07	$51.85	$4.87	$121.79	$66.14	$51.85	$4.92	$122.91	$1.07	$0.00	$0.05	$1.12	0.9%	0.0%	0.0%	0.9%	9.6%
600	$76.29	$62.22	$5.77	$144.28	$77.58	$62.22	$5.83	$145.63	$1.29	$0.00	$0.06	$1.35	0.9%	0.0%	0.0%	0.9%	7.7%
700	$87.51	$72.59	$6.67	$166.77	$89.01	$72.59	$6.73	$168.33	$1.50	$0.00	$0.06	$1.56	0.9%	0.0%	0.0%	0.9%	19.0%
1,200	$143.62	$124.44	$11.17	$279.23	$146.19	$124.44	$11.28	$281.91	$2.57	$0.00	$0.11	$2.68	0.9%	0.0%	0.0%	1.0%	6.8%
2,000	$233.40	$207.40	$18.37	$459.17	$237.68	$207.40	$18.55	$463.63	$4.28	$0.00	$0.18	$4.46	0.9%	0.0%	0.0%	1.0%	2.3%

		Rates Effective October 1, 2020 (s)	Proposed Rates (t)	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	$0.00212	$0.00224	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(7)	CapEx Factor Charge	$0.00396	$0.00598	
(8)	CapEx Reconciliation Factor	$0.00090	$0.00090	
(9)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	
(10)	Pension Adjustment Factor	($0.00073)	($0.00073)	
(11)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12)	Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(13)	Performance Incentive Factor	$0.00005	$0.00005	
(14)	Low Income Discount Recovery Factor	$0.00176	$0.00176	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00266	$0.00266	
(17)	Base Transmission Charge	$0.03096	$0.03096	Transmission Charge
(18)	Transmission Adjustment Factor	($0.00189)	($0.00189)	
(19)	Transmission Uncollectible Factor	$0.00038	$0.00038	
(20)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(21)	Transition Adjustment	($0.00008)	($0.00008)	
(22)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(23)	Standard Offer Service Base Charge	$0.09568	$0.09568	Supply Services Energy Charge
(24)	SOS Adjustment Factor	($0.00294)	($0.00294)	
(25)	SOS Adminstrative Cost Adjustment Factor	$0.00230	$0.00230	
(26)	Renewable Energy Standard Charge	$0.00866	$0.00866	

	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	$0.02945	$0.02945
(31)	Distribution Energy Charge	kWh x	$0.05809	$0.06023
(32)	Transition Charge	kWh x	($0.00082)	($0.00082)
(33)	Energy Efficiency Programs	kWh x	$0.01353	$0.01353
(34)	Renewable Energy Distribution Charge	kWh x	$0.01197	$0.01197
(35)	Supply Services Energy Charge	kWh x	$0.10370	$0.10370

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (t): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

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

	Rates Effective October 1, 2020						Proposed Rates						$ 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
			(d) = [(b)+(c)] x-.25	(e) = (b) + (c) + (d)					(j) = [(h)+(i)] x-.25	(k) = (h) + (i) + (j)			(n) = [(h)+(j)] - [(b)+(d)]			(q) = (n) + (o) + (p)	(r) = (n) ÷ [(b)+(d)]				
(a)	(b)	(c)			(f)	(g) = (e) + (f)	(h)	(i)			(l)	(m) = (k) + (l)		(o) = (i) - (c)	(p) = (l) - (f)			(s) = (o) ÷ (c)	(t) = (p) ÷ (f)	(u) = (q) ÷ (g)	(v)
150	$25.53	$15.56	($10.27)	$30.82	$1.28	$32.10	$25.85	$15.56	($10.35)	$31.06	$1.29	$32.35	$0.24	$0.00	$0.01	$0.25	0.7%	0.0%	0.0%	0.8%	32.1%
300	$42.10	$31.11	($18.30)	$54.91	$2.29	$57.20	$42.74	$31.11	($18.46)	$55.39	$2.31	$57.70	$0.48	$0.00	$0.02	$0.50	0.8%	0.0%	0.0%	0.9%	15.4%
400	$53.14	$41.48	($23.66)	$70.96	$2.96	$73.92	$54.00	$41.48	($23.87)	$71.61	$2.98	$74.59	$0.65	$0.00	$0.02	$0.67	0.9%	0.0%	0.0%	0.9%	12.5%
500	$64.19	$51.85	($29.01)	$87.03	$3.63	$90.66	$65.26	$51.85	($29.28)	$87.83	$3.66	$91.49	$0.80	$0.00	$0.03	$0.83	0.9%	0.0%	0.0%	0.9%	9.6%
600	$75.24	$62.22	($34.37)	$103.09	$4.30	$107.39	$76.52	$62.22	($34.69)	$104.05	$4.34	$108.39	$0.96	$0.00	$0.04	$1.00	0.9%	0.0%	0.0%	0.9%	7.2%
700	$86.28	$72.59	($39.72)	$119.15	$4.96	$124.11	$87.78	$72.59	($40.09)	$120.28	$5.01	$125.29	$1.13	$0.00	$0.05	$1.18	0.9%	0.0%	0.0%	1.0%	16.4%
1,200	$141.51	$124.44	($66.49)	$199.46	$8.31	$207.77	$144.08	$124.44	($67.13)	$201.39	$8.39	$209.78	$1.93	$0.00	$0.08	$2.01	0.9%	0.0%	0.0%	1.0%	5.2%
2,000	$229.88	$207.40	($109.32)	$327.96	$13.67	$341.63	$234.16	$207.40	($110.39)	$331.17	$13.80	$344.97	$3.21	$0.00	$0.13	$3.34	0.9%	0.0%	0.0%	1.0%	1.6%

		Rates Effective October 1, 2020 (w)	Proposed Rates (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	
(5)	Operating & Maintenance Expense Charge	$0.00212	$0.00224	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(7)	CapEx Factor Charge	$0.00396	$0.00598	
(8)	CapEx Reconciliation Factor	$0.00090	$0.00090	
(9)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	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	$0.00015	$0.00015	
(13)	Performance Incentive Factor	$0.00005	$0.00005	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00266	$0.00266	
(17)	Base Transmission Charge	$0.03096	$0.03096	
(18)	Transmission Adjustment Factor	($0.00189)	($0.00189)	Transmission Charge
(19)	Transmission Uncollectible Factor	$0.00038	$0.00038	
(20)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(21)	Transition Adjustment	($0.00008)	($0.00008)	
(22)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(23)	Standard Offer Service Base Charge	$0.09568	$0.09568	
(24)	SOS Adjustment Factor	($0.00294)	($0.00294)	Supply Services Energy Charge
(25)	SOS Adminstrative Cost Adjustment Factor	$0.00230	$0.00230	
(26)	Renewable Energy Standard Charge	$0.00866	$0.00866	
	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	$0.02945	$0.02945	
(31)	Distribution Energy Charge	$0.05633	$0.05847	
(32)	Transition Charge	($0.00082)	($0.00082)	
(33)	Energy Efficiency Programs	$0.01353	$0.01353	
(34)	Renewable Energy Distribution Charge	$0.01197	$0.01197	
(35)	Supply Services Energy Charge	$0.10370	$0.10370	
(36)	Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

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

Monthly kWh	Rates Effective October 1, 2020						Proposed Rates						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage of Customers
	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	
(a)	(b)	(c)	(d) = [(b)+(c)] x-.30	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.30	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) ÷ [(b)+(d)]	(s) = (o) ÷ (c)	(t) = (p) ÷ (f)	(u) = (q) ÷ (g)	(v)
150	$25.53	$15.56	($12.33)	$28.76	$1.20	$29.96	$25.85	$15.56	($12.42)	$28.99	$1.21	$30.20	$0.23	$0.00	$0.01	$0.24	0.8%	0.0%	0.0%	0.8%	32.1%
300	$42.10	$31.11	($21.96)	$51.25	$2.14	$53.39	$42.74	$31.11	($22.16)	$51.69	$2.15	$53.84	$0.44	$0.00	$0.01	$0.45	0.8%	0.0%	0.0%	0.8%	15.4%
400	$53.14	$41.48	($28.39)	$66.23	$2.76	$68.99	$54.00	$41.48	($28.64)	$66.84	$2.79	$69.63	$0.61	$0.00	$0.03	$0.64	0.9%	0.0%	0.0%	0.9%	12.5%
500	$64.19	$51.85	($34.81)	$81.23	$3.38	$84.61	$65.26	$51.85	($35.13)	$81.98	$3.42	$85.40	$0.75	$0.00	$0.04	$0.79	0.9%	0.0%	0.0%	0.9%	9.6%
600	$75.24	$62.22	($41.24)	$96.22	$4.01	$100.23	$76.52	$62.22	($41.62)	$97.12	$4.05	$101.17	$0.90	$0.00	$0.04	$0.94	0.9%	0.0%	0.0%	0.9%	7.2%
700	$86.28	$72.59	($47.66)	$111.21	$4.63	$115.84	$87.78	$72.59	($48.11)	$112.26	$4.68	$116.94	$1.05	$0.00	$0.05	$1.10	0.9%	0.0%	0.0%	0.9%	16.4%
1,200	$141.51	$124.44	($79.79)	$186.16	$7.76	$193.92	$144.08	$124.44	($80.56)	$187.96	$7.83	$195.79	$1.80	$0.00	$0.07	$1.87	0.9%	0.0%	0.0%	1.0%	5.2%
2,000	$229.88	$207.40	($131.18)	$306.10	$12.75	$318.85	$234.16	$207.40	($132.47)	$309.09	$12.88	$321.97	$2.99	$0.00	$0.13	$3.12	0.9%	0.0%	0.0%	1.0%	1.6%

		Rates Effective October 1, 2020 (w)	Proposed Rates (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	
(5)	Operating & Maintenance Expense Charge	$0.00212	$0.00224	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(7)	CapEx Factor Charge	$0.00396	$0.00598	
(8)	CapEx Reconciliation Factor	$0.00090	$0.00090	
(9)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	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	$0.00015	$0.00015	
(13)	Performance Incentive Factor	$0.00005	$0.00005	
(14)	Low Income Discount Recovery Factor	$0.00000	$0.00000	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00266	$0.00266	
(17)	Base Transmission Charge	$0.03096	$0.03096	
(18)	Transmission Adjustment Factor	($0.00189)	($0.00189)	Transmission Charge
(19)	Transmission Uncollectible Factor	$0.00038	$0.00038	
(20)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(21)	Transition Adjustment	($0.00008)	($0.00008)	
(22)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(23)	Standard Offer Service Base Charge	$0.09568	$0.09568	
(24)	SOS Adjustment Factor	($0.00294)	($0.00294)	Supply Services Energy Charge
(25)	SOS Adminstrative Cost Adjustment Factor	$0.00230	$0.00230	
(26)	Renewable Energy Standard Charge	$0.00866	$0.00866	
	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	$0.02945	$0.02945	
(31)	Distribution Energy Charge	$0.05633	$0.05847	
(32)	Transition Charge	($0.00082)	($0.00082)	
(33)	Energy Efficiency Programs	$0.01353	$0.01353	
(34)	Renewable Energy Distribution Charge	$0.01197	$0.01197	
(35)	Supply Services Energy Charge	$0.10370	$0.10370	
(36)	Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a). Line (7) per Section 6, Page 1, Line (3), Column (a). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

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

	Rates Effective October 1, 2020				Proposed Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	of Customers
(a)	(b)	(c)	(d)	(e)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
250	$41.13	$23.34	$2.69	$67.16	$41.51	$23.34	$2.70	$67.55	$0.38	$0.00	$0.01	$0.39	0.6%	0.0%	0.0%	0.6%	56.3%
500	$68.11	$46.67	$4.78	$119.56	$68.88	$46.67	$4.81	$120.36	$0.77	$0.00	$0.03	$0.80	0.6%	0.0%	0.0%	0.7%	16.9%
1,000	$122.06	$93.34	$8.98	$224.38	$123.60	$93.34	$9.04	$225.98	$1.54	$0.00	$0.06	$1.60	0.7%	0.0%	0.0%	0.7%	8.1%
1,500	$176.02	$140.01	$13.17	$329.20	$178.33	$140.01	$13.26	$331.60	$2.31	$0.00	$0.09	$2.40	0.7%	0.0%	0.0%	0.7%	5.0%
2,000	$229.97	$186.68	$17.36	$434.01	$233.05	$186.68	$17.49	$437.22	$3.08	$0.00	$0.13	$3.21	0.7%	0.0%	0.0%	0.7%	13.6%

		Rates Effective October 1, 2020	Proposed Rates	Line Item on Bill
		(o)	(p)	
(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	$0.00212	$\boxed{\$0.00215}$	
(6)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(7)	CapEx Factor Charge	$0.00339	$\boxed{\$0.00490}$	
(8)	CapEx Reconciliation Factor	$0.00085	$0.00085	
(9)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	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	$0.00015	$0.00015	
(13)	Performance Incentive Factor	$0.00005	$0.00005	
(14)	Low Income Discount Recovery Factor	$0.00176	$0.00176	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00266	$0.00266	
(17)	Base Transmission Charge	$0.03110	$0.03110	
(18)	Transmission Adjustment Factor	($0.00467)	($0.00467)	Transmission Charge
(19)	Transmission Uncollectible Factor	$0.00031	$0.00031	
(20)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(21)	Transition Adjustment	($0.00008)	($0.00008)	
(22)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(23)	Standard Offer Service Base Charge	$0.08150	$0.08150	
(24)	SOS Adjustment Factor	$0.00094	$0.00094	Supply Services Energy Charge
(25)	SOS Adminstrative Cost Adjustment Factor	$0.00224	$0.00224	
(26)	Renewable Energy Standard Charge	$0.00866	$0.00866	
	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	$0.02674	$0.02674	
(31)	Distribution Energy Charge	$0.05649	$\boxed{\$0.05803}$	
(32)	Transition Charge	($0.00082)	($0.00082)	
(33)	Energy Efficiency Programs	$0.01353	$0.01353	
(34)	Renewable Energy Distribution Charge	$0.01197	$0.01197	
(35)	Supply Services Energy Charge	$0.09334	$0.09334	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (p): Line (5) per Section 6, Page 1, Line (1), Column (b). Line (7) per Section 6, Page 1, Line (3), Column (b). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

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

			Rates Effective October 1, 2020				Proposed Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i)	Delivery Services (j)	Supply Services (k)	GET (l)	Total (m)
20	200	4,000	$526.47	$373.36	$37.49	$937.32	$531.67	$373.36	$37.71	$942.74	$5.20	$0.00	$0.22	$5.42	0.6%	0.0%	0.0%	0.6%
50	200	10,000	$1,166.85	$933.40	$87.51	$2,187.76	$1,187.05	$933.40	$88.35	$2,208.80	$20.20	$0.00	$0.84	$21.04	0.9%	0.0%	0.0%	1.0%
100	200	20,000	$2,234.15	$1,866.80	$170.87	$4,271.82	$2,279.35	$1,866.80	$172.76	$4,318.91	$45.20	$0.00	$1.89	$47.09	1.1%	0.0%	0.0%	1.1%
150	200	30,000	$3,301.45	$2,800.20	$254.24	$6,355.89	$3,371.65	$2,800.20	$257.16	$6,429.01	$70.20	$0.00	$2.92	$73.12	1.1%	0.0%	0.0%	1.2%
20	300	6,000	$617.53	$560.04	$49.07	$1,226.64	$622.93	$560.04	$49.29	$1,232.26	$5.40	$0.00	$0.22	$5.62	0.4%	0.0%	0.0%	0.5%
50	300	15,000	$1,394.50	$1,400.10	$116.44	$2,911.04	$1,415.20	$1,400.10	$117.30	$2,932.60	$20.70	$0.00	$0.86	$21.56	0.7%	0.0%	0.0%	0.7%
100	300	30,000	$2,689.45	$2,800.20	$228.74	$5,718.39	$2,735.65	$2,800.20	$230.66	$5,766.51	$46.20	$0.00	$1.92	$48.12	0.8%	0.0%	0.0%	0.8%
150	300	45,000	$3,984.40	$4,200.30	$341.03	$8,525.73	$4,056.10	$4,200.30	$344.02	$8,600.42	$71.70	$0.00	$2.99	$74.69	0.8%	0.0%	0.0%	0.9%
20	400	8,000	$708.59	$746.72	$60.64	$1,515.95	$714.19	$746.72	$60.87	$1,521.78	$5.60	$0.00	$0.23	$5.83	0.4%	0.0%	0.0%	0.4%
50	400	20,000	$1,622.15	$1,866.80	$145.37	$3,634.32	$1,643.35	$1,866.80	$146.26	$3,656.41	$21.20	$0.00	$0.89	$22.09	0.6%	0.0%	0.0%	0.6%
100	400	40,000	$3,144.75	$3,733.60	$286.60	$7,164.95	$3,191.95	$3,733.60	$288.56	$7,214.11	$47.20	$0.00	$1.96	$49.16	0.7%	0.0%	0.0%	0.7%
150	400	60,000	$4,667.35	$5,600.40	$427.82	$10,695.57	$4,740.55	$5,600.40	$430.87	$10,771.82	$73.20	$0.00	$3.05	$76.25	0.7%	0.0%	0.0%	0.7%
20	500	10,000	$799.65	$933.40	$72.21	$1,805.26	$805.45	$933.40	$72.45	$1,811.30	$5.80	$0.00	$0.24	$6.04	0.3%	0.0%	0.0%	0.3%
50	500	25,000	$1,849.80	$2,333.50	$174.30	$4,357.60	$1,871.50	$2,333.50	$175.21	$4,380.21	$21.70	$0.00	$0.91	$22.61	0.5%	0.0%	0.0%	0.5%
100	500	50,000	$3,600.05	$4,667.00	$344.46	$8,611.51	$3,648.25	$4,667.00	$346.47	$8,661.72	$48.20	$0.00	$2.01	$50.21	0.6%	0.0%	0.0%	0.6%
150	500	75,000	$5,350.30	$7,000.50	$514.62	$12,865.42	$5,425.00	$7,000.50	$517.73	$12,943.23	$74.70	$0.00	$3.11	$77.81	0.6%	0.0%	0.0%	0.6%
20	600	12,000	$890.71	$1,120.08	$83.78	$2,094.57	$896.71	$1,120.08	$84.03	$2,100.82	$6.00	$0.00	$0.25	$6.25	0.3%	0.0%	0.0%	0.3%
50	600	30,000	$2,077.45	$2,800.20	$203.24	$5,080.89	$2,099.65	$2,800.20	$204.16	$5,104.01	$22.20	$0.00	$0.92	$23.12	0.4%	0.0%	0.0%	0.5%
100	600	60,000	$4,055.35	$5,600.40	$402.32	$10,058.07	$4,104.55	$5,600.40	$404.37	$10,109.32	$49.20	$0.00	$2.05	$51.25	0.5%	0.0%	0.0%	0.5%
150	600	90,000	$6,033.25	$8,400.60	$601.41	$15,035.26	$6,109.45	$8,400.60	$604.59	$15,114.64	$76.20	$0.00	$3.18	$79.38	0.5%	0.0%	0.0%	0.5%

	Rates Effective October 1, 2020 (o)	Proposed Rates (p)	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)	$0.97	$1.45	
(6) Distribution Charge (per kWh)	$0.00476	$0.00476	Distribution Energy Charge
(7) Operating & Maintenance Expense Charge	$0.00169	$0.00179	
(8) Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(9) CapEx Reconciliation Factor	$0.00064	$0.00064	
(10) Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	
(11) Pension Adjustment Factor	($0.00073)	($0.00073)	
(12) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13) Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(14) Performance Incentive Factor	$0.00005	$0.00005	
(15) Low Income Discount Recovery Factor	$0.00176	$0.00176	
(16) Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(17) Net Metering Charge	$0.00266	$0.00266	
(18) Transmission Demand Charge	$4.37	$4.37	Transmission Demand Charge
(19) Base Transmission Charge	$0.01214	$0.01214	Transmission Adjustment
(20) Transmission Adjustment Factor	($0.00399)	($0.00399)	
(21) Transmission Uncollectible Factor	$0.00030	$0.00030	
(22) Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(23) Transition Adjustment	($0.00008)	($0.00008)	
(24) Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(25) Standard Offer Service Base Charge	$0.08150	$0.08150	Supply Services Energy Charge
(26) SOS Adjustment Factor	$0.00094	$0.00094	
(27) SOS Adminstrative Cost Adjustment Factor	$0.00224	$0.00224	
(28) Renewable Energy Standard Charge	$0.00866	$0.00866	
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	$0.00845	$0.00845	
(33) Distribution Energy Charge	$0.01240	$0.01250	
(34) Distribution Demand Charge	$7.87	$8.35	
(35) Transmission Demand Charge	$4.37	$4.37	
(34) Transition Charge	($0.00082)	($0.00082)	
(35) Energy Efficiency Programs	$0.01353	$0.01353	
(36) Renewable Energy Distribution Charge	$0.01197	$0.01197	
(37) Supply Services Energy Charge	$0.09334	$0.09334	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (p): Line (5) per Section 6, Page 1, Line (4), Column (c). Line (7) per Section 6, Page 1, Line (1), Column (c). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

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

			Rates Effective October 1, 2020				Proposed Rates				$ Increase (Decrease)				Increase (Decrease) % of Total Bill			
kW	Monthly Power Hours Use (a)	kWh	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (b)	Supply Services (c)	GET (d)	Total (e)	Delivery Services (f)	Supply Services (g)	GET (h)	Total (i)	Delivery Services (j)	Supply Services (k)	GET (l)	Total (m)
200	200	40,000	$4,172.35	$2,951.60	$296.83	$7,420.78	$4,175.15	$2,951.60	$296.95	$7,423.70	$2.80	$0.00	$0.12	$2.92	0.0%	0.0%	0.0%	0.0%
750	200	150,000	$15,316.45	$11,068.50	$1,099.37	$27,484.32	$15,612.95	$11,068.50	$1,111.73	$27,793.18	$296.50	$0.00	$12.36	$308.86	1.1%	0.0%	0.0%	1.1%
1,000	200	200,000	$20,381.95	$14,758.00	$1,464.16	$36,604.11	$20,811.95	$14,758.00	$1,482.08	$37,052.03	$430.00	$0.00	$17.92	$447.92	1.2%	0.0%	0.0%	1.2%
1,500	200	300,000	$30,512.95	$22,137.00	$2,193.75	$54,843.70	$31,209.95	$22,137.00	$2,222.79	$55,569.74	$697.00	$0.00	$29.04	$726.04	1.3%	0.0%	0.1%	1.3%
2,500	200	500,000	$50,774.95	$36,895.00	$3,652.91	$91,322.86	$52,005.95	$36,895.00	$3,704.21	$92,605.16	$1,231.00	$0.00	$51.30	$1,282.30	1.3%	0.0%	0.1%	1.4%
5,000	200	1,000,000	$101,429.95	$73,790.00	$7,300.83	$182,520.78	$103,995.95	$73,790.00	$7,407.75	$185,193.70	$2,566.00	$0.00	$106.92	$2,672.92	1.4%	0.0%	0.1%	1.5%
7,500	200	1,500,000	$152,084.95	$110,685.00	$10,948.75	$273,718.70	$155,985.95	$110,685.00	$11,111.29	$277,782.24	$3,901.00	$0.00	$162.54	$4,063.54	1.4%	0.0%	0.1%	1.5%
10,000	200	2,000,000	$202,739.95	$147,580.00	$14,596.67	$364,916.62	$207,975.95	$147,580.00	$14,814.83	$370,370.78	$5,236.00	$0.00	$218.16	$5,454.16	1.4%	0.0%	0.1%	1.5%
20,000	200	4,000,000	$405,359.95	$295,160.00	$29,188.33	$729,708.28	$415,935.95	$295,160.00	$29,629.00	$740,724.95	$10,576.00	$0.00	$440.67	$11,016.67	1.4%	0.0%	0.1%	1.5%
200	300	60,000	$5,127.55	$4,427.40	$398.12	$9,953.07	$5,131.75	$4,427.40	$398.30	$9,957.45	$4.20	$0.00	$0.18	$4.38	0.0%	0.0%	0.0%	0.0%
750	300	225,000	$18,898.45	$16,602.75	$1,479.22	$36,980.42	$19,200.20	$16,602.75	$1,491.79	$37,294.74	$301.75	$0.00	$12.57	$314.32	0.8%	0.0%	0.0%	0.8%
1,000	300	300,000	$25,157.95	$22,137.00	$1,970.62	$49,265.57	$25,594.95	$22,137.00	$1,988.83	$49,720.78	$437.00	$0.00	$18.21	$455.21	0.9%	0.0%	0.0%	0.9%
1,500	300	450,000	$37,676.95	$33,205.50	$2,953.44	$73,835.89	$38,384.45	$33,205.50	$2,982.91	$74,572.86	$707.50	$0.00	$29.47	$736.97	1.0%	0.0%	0.0%	1.0%
2,500	300	750,000	$62,714.95	$55,342.50	$4,919.06	$122,976.51	$63,963.45	$55,342.50	$4,971.08	$124,277.03	$1,248.50	$0.00	$52.02	$1,300.52	1.0%	0.0%	0.0%	1.1%
5,000	300	1,500,000	$125,309.95	$110,685.00	$9,833.12	$245,828.07	$127,910.95	$110,685.00	$9,941.50	$248,537.45	$2,601.00	$0.00	$108.38	$2,709.38	1.1%	0.0%	0.0%	1.1%
7,500	300	2,250,000	$187,904.95	$166,027.50	$14,747.19	$368,679.64	$191,858.45	$166,027.50	$14,911.92	$372,797.87	$3,953.50	$0.00	$164.73	$4,118.23	1.1%	0.0%	0.0%	1.1%
10,000	300	3,000,000	$250,499.95	$221,370.00	$19,661.25	$491,531.20	$255,805.95	$221,370.00	$19,882.33	$497,058.28	$5,306.00	$0.00	$221.08	$5,527.08	1.1%	0.0%	0.0%	1.1%
20,000	300	6,000,000	$500,879.95	$442,740.00	$39,317.50	$982,937.45	$511,595.95	$442,740.00	$39,764.00	$994,099.95	$10,716.00	$0.00	$446.50	$11,162.50	1.1%	0.0%	0.0%	1.1%
200	400	80,000	$6,082.75	$5,903.20	$499.41	$12,485.36	$6,088.35	$5,903.20	$499.65	$12,491.20	$5.60	$0.00	$0.24	$5.84	0.0%	0.0%	0.0%	0.0%
750	400	300,000	$22,480.45	$22,137.00	$1,859.06	$46,476.51	$22,787.45	$22,137.00	$1,871.85	$46,796.30	$307.00	$0.00	$12.79	$319.79	0.7%	0.0%	0.0%	0.7%
1,000	400	400,000	$29,933.95	$29,516.00	$2,477.08	$61,927.03	$30,377.95	$29,516.00	$2,495.58	$62,389.53	$444.00	$0.00	$18.50	$462.50	0.7%	0.0%	0.0%	0.7%
1,500	400	600,000	$44,840.95	$44,274.00	$3,713.12	$92,828.07	$45,558.95	$44,274.00	$3,743.04	$93,575.99	$718.00	$0.00	$29.92	$747.92	0.8%	0.0%	0.0%	0.8%
2,500	400	1,000,000	$74,654.95	$73,790.00	$6,185.21	$154,630.16	$75,920.95	$73,790.00	$6,237.96	$155,948.91	$1,266.00	$0.00	$52.75	$1,318.75	0.8%	0.0%	0.0%	0.9%
5,000	400	2,000,000	$149,189.95	$147,580.00	$12,365.42	$309,135.37	$151,825.95	$147,580.00	$12,475.25	$311,881.20	$2,636.00	$0.00	$109.83	$2,745.83	0.9%	0.0%	0.0%	0.9%
7,500	400	3,000,000	$223,724.95	$221,370.00	$18,545.62	$463,640.57	$227,730.95	$221,370.00	$18,712.54	$467,813.49	$4,006.00	$0.00	$166.92	$4,172.92	0.9%	0.0%	0.0%	0.9%
10,000	400	4,000,000	$298,259.95	$295,160.00	$24,725.83	$618,145.78	$303,635.95	$295,160.00	$24,949.83	$623,745.78	$5,376.00	$0.00	$224.00	$5,600.00	0.9%	0.0%	0.0%	0.9%
20,000	400	8,000,000	$596,399.95	$590,320.00	$49,446.67	$1,236,166.62	$607,255.95	$590,320.00	$49,899.00	$1,247,474.95	$10,856.00	$0.00	$452.33	$11,308.33	0.9%	0.0%	0.0%	0.9%
200	500	100,000	$7,037.95	$7,379.00	$600.71	$15,017.66	$7,044.95	$7,379.00	$601.00	$15,024.95	$7.00	$0.00	$0.29	$7.29	0.0%	0.0%	0.0%	0.0%
750	500	375,000	$26,062.45	$27,671.25	$2,238.90	$55,972.60	$26,374.70	$27,671.25	$2,251.91	$56,297.86	$312.25	$0.00	$13.01	$325.26	0.6%	0.0%	0.0%	0.6%
1,000	500	500,000	$34,709.95	$36,895.00	$2,983.54	$74,588.49	$35,160.95	$36,895.00	$3,002.33	$75,058.28	$451.00	$0.00	$18.79	$469.79	0.6%	0.0%	0.0%	0.6%
1,500	500	750,000	$52,004.95	$55,342.50	$4,472.81	$111,820.26	$52,733.45	$55,342.50	$4,503.16	$112,579.11	$728.50	$0.00	$30.35	$758.85	0.7%	0.0%	0.0%	0.7%
2,500	500	1,250,000	$86,594.95	$92,237.50	$7,451.35	$186,283.80	$87,878.45	$92,237.50	$7,504.83	$187,620.78	$1,283.50	$0.00	$53.48	$1,336.98	0.7%	0.0%	0.0%	0.7%
5,000	500	2,500,000	$173,069.95	$184,475.00	$14,897.71	$372,442.66	$175,740.95	$184,475.00	$15,009.00	$375,224.95	$2,671.00	$0.00	$111.29	$2,782.29	0.7%	0.0%	0.0%	0.7%
7,500	500	3,750,000	$259,544.95	$276,712.50	$22,344.06	$558,601.51	$263,603.45	$276,712.50	$22,513.17	$562,829.12	$4,058.50	$0.00	$169.11	$4,227.61	0.7%	0.0%	0.0%	0.8%
10,000	500	5,000,000	$346,019.95	$368,950.00	$29,790.42	$744,760.37	$351,465.95	$368,950.00	$30,017.33	$750,433.28	$5,446.00	$0.00	$226.91	$5,672.91	0.7%	0.0%	0.0%	0.8%
20,000	500	10,000,000	$691,919.95	$737,900.00	$59,575.84	$1,489,395.79	$702,915.95	$737,900.00	$60,034.00	$1,500,849.95	$10,996.00	$0.00	$458.16	$11,454.16	0.7%	0.0%	0.0%	0.8%
200	600	120,000	$7,993.15	$8,854.80	$702.00	$17,549.95	$8,001.55	$8,854.80	$702.35	$17,558.70	$8.40	$0.00	$0.35	$8.75	0.0%	0.0%	0.0%	0.0%
750	600	450,000	$29,644.45	$33,205.50	$2,618.75	$65,468.70	$29,961.95	$33,205.50	$2,631.98	$65,799.43	$317.50	$0.00	$13.23	$330.73	0.5%	0.0%	0.0%	0.5%
1,000	600	600,000	$39,485.95	$44,274.00	$3,490.00	$87,249.95	$39,943.95	$44,274.00	$3,509.08	$87,727.03	$458.00	$0.00	$19.08	$477.08	0.5%	0.0%	0.0%	0.5%
1,500	600	900,000	$59,168.95	$66,411.00	$5,232.50	$130,812.45	$59,907.95	$66,411.00	$5,263.29	$131,582.24	$739.00	$0.00	$30.79	$769.79	0.6%	0.0%	0.0%	0.6%
2,500	600	1,500,000	$98,534.95	$110,685.00	$8,717.50	$217,937.45	$99,835.95	$110,685.00	$8,771.71	$219,292.66	$1,301.00	$0.00	$54.21	$1,355.21	0.6%	0.0%	0.0%	0.6%
5,000	600	3,000,000	$196,949.95	$221,370.00	$17,430.00	$435,749.95	$199,655.95	$221,370.00	$17,542.75	$438,568.70	$2,706.00	$0.00	$112.75	$2,818.75	0.6%	0.0%	0.0%	0.6%
7,500	600	4,500,000	$295,364.95	$332,055.00	$26,142.50	$653,562.45	$299,475.95	$332,055.00	$26,313.79	$657,844.74	$4,111.00	$0.00	$171.29	$4,282.29	0.6%	0.0%	0.0%	0.7%
10,000	600	6,000,000	$393,779.95	$442,740.00	$34,855.00	$871,374.95	$399,295.95	$442,740.00	$35,084.83	$877,120.78	$5,516.00	$0.00	$229.83	$5,745.83	0.6%	0.0%	0.0%	0.7%
20,000	600	12,000,000	$787,439.95	$885,480.00	$69,705.00	$1,742,624.95	$798,575.95	$885,480.00	$70,169.00	$1,754,224.95	$11,136.00	$0.00	$464.00	$11,600.00	0.6%	0.0%	0.0%	0.7%

		Rates Effective October 1, 2020 (o)	Proposed Rates (p)	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)	$0.94	$1.46	
(6)	Distribution Charge (per kWh)	$0.00430	$0.00430	
(7)	Operating & Maintenance Expense Charge	$0.00086	$0.00093	
(8)	Operating & Maintenance Expense Reconciliation Factor	$0.00002	$0.00002	
(9)	CapEx Reconciliation Factor	$0.00033	$0.00033	
(10)	Revenue Decoupling Adjustment Factor	$0.00118	$0.00118	Distribution Energy Charge
(11)	Pension Adjustment Factor	($0.00073)	($0.00073)	
(12)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13)	Arrearage Management Adjustment Factor	$0.00015	$0.00015	
(14)	Performance Incentive Factor	$0.00005	$0.00005	
(15)	Low Income Discount Recovery Factor	$0.00176	$0.00176	
(16)	Long-term Contracting for Renewable Energy Charge	$0.00931	$0.00931	Renewable Energy Distribution Charge
(17)	Net Metering Charge	$0.00266	$0.00266	
(18)	Transmission Demand Charge	$4.47	$4.47	Transmission Demand Charge
(19)	Base Transmission Charge	$0.01264	$0.01264	
(20)	Transmission Adjustment Factor	($0.00070)	($0.00070)	Transmission Adjustment
(21)	Transmission Uncollectible Factor	$0.00034	$0.00034	
(22)	Base Transition Charge	($0.00074)	($0.00074)	Transition Charge
(23)	Transition Adjustment	($0.00008)	($0.00008)	
(24)	Energy Efficiency Program Charge	$0.01353	$0.01353	Energy Efficiency Programs
(25)	Standard Offer Service Base Charge	$0.05946	$0.05946	
(26)	SOS Adjustment Factor	$0.00381	$0.00381	Supply Services Energy Charge
(27)	SOS Adminstrative Cost Adjustment Factor	$0.00186	$0.00186	
(28)	Renewable Energy Standard Charge	$0.00866	$0.00866	
	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	$0.01228	$0.01228	
(33)	Distribution Energy Charge	$0.01080	$0.01087	
(34)	Distribution Demand Charge	$6.24	$6.76	
(35)	Transmission Demand Charge	$4.47	$4.47	
(34)	Transition Charge	($0.00082)	($0.00082)	
(35)	Energy Efficiency Programs	$0.01353	$0.01353	
(36)	Renewable Energy Distribution Charge	$0.01197	$0.01197	
(37)	Supply Services Energy Charge	$0.07379	$0.07379	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020
Column (p): Line (5) per Section 6, Page 1, Line (4), Column (e). Line (7) per Section 6, Page 1, Line (1), Column (e). All other rates per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2020, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2020

Testimony of
Melissa A. Little

PRE-FILED DIRECT TESTIMONY

OF

MELISSA A. LITTLE

December 21, 2020

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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 at National Grid and responsibilities in that position.

A. I am a Director for New England Revenue Requirements in the Strategy and Regulation department of National Grid USA Service Company, Inc. (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 PricewaterhouseCoopers 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 filed testimony or testified before the Rhode Island Public Utilities Commission (Commission)?

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

II. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor Section 5 of the FY 2022 Electric ISR Plan (the Electric ISR Plan or Plan), which describes the calculation of the Company's revenue requirement for FY 2022 in Attachment 1 of that section. The revenue requirement is based on the Electric ISR Plan operation and maintenance (O&M) expenses and capital investment, which are described in the joint testimony of Ms. Patricia C. Easterly, Mr. Ryan A. Moe, and Ms. Caitlin Broderick.

III. ISR PLAN REVENUE REQUIREMENT

Q. Please summarize the revenue requirement for the Company's Electric ISR Plan.

A. As shown on Attachment 1 to Section 5, Page 1, Column (b), the Company's Electric ISR Plan cumulative revenue requirement is $41,443,447 and consists of the following elements: (1) operation and maintenance (O&M) expense associated with the Company's vegetation management (VM) activities, the Company's Inspection and Maintenance (I&M) program, and Other Programs, (2) the Company's capital investment in electric utility infrastructure, and (3) the FY 2022 Property Tax Recovery Adjustment. Lines 1, 2 and 3 of Column (b) reflect the forecasted FY 2022 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $10,800,000, $896,000, and $287,000 respectively. The Electric ISR Plan includes the recovery of O&M inspection and maintenance costs associated with the Company's Contact Voltage Detection and Repair Program (Contact Voltage Program), mandated by R.I. Gen. Laws § 39-2-25 and approved by the Commission in Docket No. 4237. Contact Voltage Program costs are included from the $896,000 of I&M expenses referred to above. Prior ISR proposals included a reduction to I&M expenses related to Contact Voltage Program costs that were being recovered in base rates in RIPUC Docket No. 4323; however, this reduction is no longer required because in the Company's most recent general rate case in RIPUC Docket No. 4770, Contact Voltage Program costs were excluded from the cost of service to be recovered in base rates, effective September 1, 2018.

For illustration purposes only, Column (c) of Page 1 provides the FY 2023 revenue requirement for the respective vintage year capital investments. Notably, these amounts will be trued up to actual investment activity after the conclusion of the fiscal year, with rate adjustments for the revenue requirement differences incorporated in future ISR filings.

Q. Did the Company calculate the Electric ISR Plan revenue requirement in the same fashion as calculated in the previous Electric ISR Factor submissions?

A. Yes.

Q. Please explain the increase of FY 2022 Electric ISR Plan revenue requirement over the amount currently being billed for Electric ISR Plan?

A. As mentioned above, the Company's FY 2022 Electric ISR Plan revenue requirement is $8,501,929 higher than the FY 2021 Electric ISR Plan revenue requirement. Of the total $41,443,447 revenue requirement in FY 2022, $20,743,961 in capital investment revenue requirement and $2,506,317 in property tax recovery adjustment are associated with incremental non-growth ISR capital investment for FY 2018 through FY 2021, which have been approved in previous Electric ISR plan or reconciliation filings. The increase in the FY 2022 revenue requirement associated with previous fiscal years' capital investments compared to the approved FY 2021 Plan revenue requirement on that same investment totals $4,846,084 and is mainly due to the half-year convention applied in the year of spend. As a result, the FY 2022 revenue requirement on vintage year FY 2021 incremental non-growth ISR capital investment increased by $4,381,838 from the FY 2021 revenue requirement on the same investment. The movement in the property tax recovery adjustment related to prior years' investment as well as rate base embedded in current distribution rates is a decrease of $2,445,691. The remainder of the FY 2022 revenue requirement increase, or $6,210,169, is related to the FY 2022 proposed non-growth ISR incremental capital investment and the resulting increase in property tax expense due to that incremental investment, offset by a slight decrease in total FY 2022 VM, I&M and Other Program O&M expense of $108,633.

Q. Does the Company plan to update the Electric ISR Plan revenue requirement calculation subsequent to the date of this filing?

A. Yes. The Company will file its FY 2020 federal income tax return in December 2020, coincident with the submission of this filing. The Company will compare the results of the actual FY 2020 federal tax return with the tax assumptions used to calculate deferred federal income taxes included in rate base in the FY 2020, FY 2021 and FY 2020 vintage revenue requirement calculations and assess any impact to the Electric ISR Plan revenue requirement. The Company will then file a revised FY 2022 Electric ISR revenue requirement prior to hearings in this docket which will quantify the impact of any revisions to accumulated deferred income taxes on the Electric ISR Plan revenue requirement, including any further implications of the Tax Act.

IV. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes.

Testimony of
Daniel E. Gallagher

PRE-FILED DIRECT TESTIMONY

OF

DANIEL E. GALLAGHER

December 21, 2020

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I. <u>INTRODUCTION AND QUALIFICATIONS</u>

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 Analyst, New England Electric Pricing, in the Strategy and Regulation department of National Grid USA Service Company (NGSC). This department provides rate-related support to The Narragansett Electric Company d/b/a National Grid (National Grid or 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 NGSC as an

Electric Pricing Analyst in the Strategy and Regulation group, performing electric rate analysis for National Grid's New England electric distribution companies.

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

A. Yes, I provided pre-filed direct testimony on May 15, 2020 to support the Company's proposal in its annual Revenue Decoupling Mechanism Reconciliation filing for 2020 (RIPUC Docket No. 5030).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the calculation of the proposed factors designed to recover the fiscal year (FY) 2022 revenue requirement on cumulative actual and forecasted incremental capital investment through March 31, 2022 and FY 2022 operation and maintenance (O&M) expense resulting from the Company's FY 2022 Infrastructure, Safety, and Reliability (ISR) Plan proposed in this filing and to provide the customer bill impacts of the proposed rate changes.

II. <u>INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION</u>

Q. Please describe the Company's ISR Plan tariff provision.

A. The Company's ISR Provision, RIPUC No. 2199, describes the process for establishing and implementing annual rate adjustments designed to recover the costs associated with the electric ISR Plan. The tariff consists of two separate mechanisms: (1) an Infrastructure Investment Mechanism (IIM) designed to recover the costs associated with incremental capital investment; and (2) an Operation and Maintenance Mechanism (O&MM) designed to recover certain annual O&M expense pertaining to Inspection and Maintenance (I&M), Vegetation Management (VM) activities, and any other O&M expense as approved by the Commission.

A. <u>Infrastructure Investment Mechanism</u>

Q. Please describe the operation of the IIM.

A. The IIM provides for the recovery of incremental capital investment through CapEx Factors. In conjunction with the filing of the annual electric ISR Plan by January 1 of each year, the Company proposes CapEx Factors for each rate class designed to recover the cumulative revenue requirement associated with forecasted and actual capital investment through the end of the upcoming ISR Plan year ending March 31, which coincides with the Company's fiscal year. The proposed CapEx Factors become effective on and after April 1 of each ISR Plan year upon Commission approval.

Q. How are the CapEx Factors designed?

A. First, the cumulative revenue requirement approved by the Commission, which will reflect both an estimate of incremental capital investment for the upcoming ISR Plan year plus the cumulative actual and forecasted incremental capital investment for prior ISR

Plan years including the current ISR Plan year, is allocated to each of the Company's rate classes based upon the rate base allocator. The rate base allocator is the percentage of total rate base allocated to each rate class taken from the Company's most recent general rate case before the Commission that contained an allocated cost of service study.

Next, unit rates for each rate class are developed from the allocated revenue requirement. For non-demand rate classes, a per kWh rate is calculated by dividing each rate class's share of the revenue requirement by its forecasted kWh deliveries for the period during which the rates will be in effect. For demand-based rate classes, Rate G-02, and Rates G-32/B-32, the CapEx Factors are per kW rates and are calculated by dividing the allocated revenue requirement for each rate class by an estimate of the kW billing demand for the period the rate will be in effect.

Q. Please explain why the revenue requirement is allocated using a rate base allocator.

A. A rate base allocator is used to allocate the revenue requirement associated with cumulative incremental capital investment to the Company's rate classes as it is similar to the manner by which the revenue requirement on capital investment would be allocated in an allocated cost of service study. Since capital investment is primarily related to plant in service, which forms the largest part of rate base, allocating the incremental capital investment using the rate base allocator contained in the allocated cost of service study in the Company's most recent general rate case is an appropriate way to spread the revenue requirement to each of the rate classes.

Q. Is the revenue requirement, which contains, in part, an estimate of incremental capital investment, and revenue generated from the CapEx Factors subject to reconciliation?

A. Yes. The Company submits a filing by August 1 of each year (the Reconciliation Filing) in which the Company proposes CapEx Reconciling Factors to become effective for the 12 months beginning October 1. In the Reconciliation Filing, the Company compares the revenue requirement on actual cumulative incremental capital investment to actual billed revenue generated from the CapEx Factors for the applicable reconciliation period, and any over- or under-recovery of the revenue requirement is credited to or recovered from customers through CapEx Reconciling Factors. The amount approved for recovery or crediting through CapEx Reconciling Factors is also subject to reconciliation with actual amounts billed through the CapEx Reconciling Factors, and any difference reflected in future CapEx Reconciling Factors.

B. Operation and Maintenance Mechanism

Q. Please describe the operation of the O&MM.

A. The O&MM provides for the recovery of the proposed O&M expense presented in the ISR Plan. The O&M Factor for each rate class is designed to recover the sum of the annual forecasted O&M expense for the upcoming ISR Plan year, as approved by the Commission in the Company's annual electric ISR Plan Filing.

Q. How are the O&M Factors designed?

A. To determine each rate class's O&M Factor, the forecasted O&M expense is allocated to each of the Company's rate classes based upon the O&M allocator derived from allocated distribution O&M expense (i.e., FERC accounts 580-598). This distribution O&M allocator is the percentage of total distribution O&M expense allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study.

Once the rate class O&M revenue requirement has been determined, per unit rates are developed for each rate class. For Large Demand Back Up Service Rate B-32, the O&M Factor for Backup Service is in the form of a demand, or per kW, rate and is calculated by dividing the allocated O&M expense for the combined rate class by an estimate of the kW billing demand for the 12 month period the factors are to be in effect, truncating the result to 2 decimal places, then applying a 90% discount by multiplying the resulting charge by 0.1. For all other rate classes, a per kWh rate is developed by dividing the allocated O&M expense by the forecasted kWh deliveries for each rate class for the period during which the rates will be in effect.

Q. Why is the O&M expense allocated using a distribution O&M allocator?

A. As with the allocation of the revenue requirement on capital investment, the O&M expense is allocated in a manner that is similar to the way these costs would be allocated in an allocated cost of service study. Therefore, the distribution O&M allocator derived from the allocated cost of service study approved in the Company's last general rate case is used to spread these costs to each of the Company's rate classes.

Q. Regarding Rates G-02 and B-32/G-32, why are the CapEx Factors designed as demand (per kW) charges and the O&M Factors as per kWh charges?

A. The current distribution rate structure for Rates G-02 and B-32/G-32 include both demand and kWh rates. The designs of the CapEx Factors and O&M Factors for these rate classes are intended to not significantly change the relationship between the existing rates and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts.

Q. Are the O&M Factors subject to reconciliation?

A. Yes. In the Company's annual ISR Reconciliation Filing, the Company proposes an

O&M Reconciling Factor to become effective for the 12 months beginning October 1. The Company compares the actual O&M expense to actual billed revenue generated from the O&M Factors for the applicable reconciliation period, and any over- or under-recovery of actual expense is credited to or recovered from customers through the O&M Reconciling Factor. The O&M Reconciling Factor is a uniform per kWh rate applicable to all rate classes. The amount approved for recovery or crediting through the O&M Reconciling Factor is subject to reconciliation with actual amounts billed through the O&M Reconciling Factor and any difference reflected in future O&M Reconciling Factors.

III. PROPOSED FACTORS

A. Capex Factors

Q. Please describe the calculation of the proposed CapEx Factors.

A. The CapEx Factors are designed to recover the revenue requirement related to cumulative incremental capital investment through the end of FY 2022. The revenue requirement of $29,460,447[1] is developed in the testimony of Company Witness Melissa A. Little. The revenue requirement is allocated to the rate classes based on the total rate base allocator, consistent with the provisions of the general rate case Amended Settlement Agreement in Docket No. 4770, and the factors are designed as described above using forecasted billing

[1] See Section 5: Attachment 1, Page 1, Line 13, Column (b).

units for the period April 1, 2021 through March 31, 2022. The calculation of the proposed CapEx Factors is set forth in the ISR Plan, Section 6, page 3.

B. O&M Factors

Q. Please describe the calculation of the proposed O&M Factors.

A. The proposed O&M Factors are designed to recover forecasted O&M expense for FY 2022. As developed in the testimony of Melissa A. Little, these expenses total $11,983,000.[2] The Company has allocated this O&M expense using a distribution O&M allocator developed from the allocated cost of service study submitted as part of the Amended Settlement Agreement in Docket No. 4770. O&M Factors are designed as I describe above. The calculation of the proposed O&M Factors is set forth in the ISR Plan, Section 6, page 2.

Q. Is the Company providing a summary of all proposed factors?

A. Yes. The Summary of Proposed Factors is presented in Section 6, page 1.

IV. BILL IMPACTS

Q. Has the Company prepared monthly bill impacts illustrating the effect of the proposed ISR factors?

A. Yes. The monthly bill impacts for each rate class are shown on Section 7 of the ISR Plan.

[2] See Section 5: Attachment 1, Page 1, Line 4, Column (b).

For a residential customer receiving Standard Offer Service, soon to become Last Resort Service, and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $1.12, or 0.9%.

V. SUMMARY OF RETAIL DELIVERY RATES

Q. Is the Company including a revised Summary of Retail Delivery Rates tariff, RIPUC No. 2095, in this filing?

A. No, the Company is not revising this tariff at this time. The Company will submit its annual Electric Retail Rate filing in February 2021 and will propose additional rate changes for effect April 1, 2021. Therefore, the Company will submit a compliance filing following the Commission's decision in both the reconciliation filing docket and this docket that will include the Summary of Retail Delivery rates tariff reflecting all of the approved rate changes for effect April 1, 2021.

VI. DOCKET 4600

Q. Did the Company apply the Docket 4600 principles of rate design to the FY 2022 Electric ISR Plan?

A. The Company did not perform a specific analysis of the rate design principles in the context of the proposed FY 2022 Electric ISR Plan. Rhode Island Gen. Laws § 39-1-27.7.1 provides for a spending plan for each fiscal year and an annual rate-reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget. The Commission has previously approved the rate design for the ISR recovery factors as part of the ISR Provision, RIPUC No. 2199, effective September 1, 2018. The Company is not proposing any changes to the current rate design as part of the FY 2022 Electric ISR Plan.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.