The Narragansett Electric Company
d/b/a National Grid

Electric Infrastructure, Safety, and Reliability Plan FY 2021 Proposal

Book 1 of 2

December 20, 2019

Docket No. 4995

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Filing Letter

nationalgrid

Jennifer Brooks Hutchinson
Acting Assistant General Counsel and Director

December 20, 2019

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: National Grid's Proposed FY 2021 Electric Infrastructure, Safety, and Reliability Plan Docket No. 4995

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's proposed Electric Infrastructure, Safety, and Reliability Plan (the Electric ISR Plan or Plan) for fiscal year 2021.[2] National Grid has developed this proposed Electric ISR Plan, which is designed to enhance the safety and reliability of the Company's electric distribution system. As required by law, the Company submitted the Plan to the Rhode Island Division of Public Utilities and Carriers (Division) for review on September 30, 2019. In preparing and refining the Plan, the Company consulted with the Division's representatives regarding the Plan, and received and responded to discovery requests from the Division. The Division has indicated general concurrence with the proposed Electric ISR Plan, including the programs and projects outlined in the Plan.

The Electric ISR Plan is designed to protect and improve the electric delivery system through repairing failed or damaged equipment, addressing load growth/migration, sustaining system viability through targeted investments that are driven primarily by condition, maintaining levels of inspection and maintenance, and operating a cost-effective vegetation management program. The Plan is intended to achieve these safety and reliability goals through a cost-effective, comprehensive work plan. The level of work that the Plan provides will sustain and enhance the safety and reliability of the Rhode Island electric distribution infrastructure and directly benefit all Rhode Island electric customers.

The proposed Electric ISR Plan addresses the following budget categories for FY 2021, or the twelve-month fiscal year ending March 31, 2021: capital spending on electric infrastructure projects; operation and maintenance (O&M) expenses for vegetation management (VM); inspection and maintenance (I&M); and Volt/Var Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion.

In addition to the Plan, this filing includes the pre-filed direct testimony of several witnesses. In joint testimony, Patricia C. Easterly, Ryan A. Moe, and Kathy Castro introduce the Plan and describe its large program components. In addition, their joint testimony presents the

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).
[2] The Electric ISR Plan is submitted in compliance with the provisions of R.I. Gen. Laws § 39-1-27.7.1.

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Company's analysis of the goals and benefit-cost framework that the Public Utilities Commission (PUC) adopted in its Report and Order No. 22851, dated July 31, 2017 and the PUC's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid, dated October 27, 2017 issued in Docket 4600A to new and incremental programs and projects in the Electric ISR Plan for which funding is being requested for the first time in FY 2021; Melissa A. Little sponsors the calculation of the Company's fiscal year 2021 revenue requirement under the Plan; and Adam S. Crary describes the calculation of the ISR factors proposed in this filing and provides the customer bill impacts from the proposed rate changes. For a residential customer receiving Standard Offer Service and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $1.43, or 1.2%.

For the PUC's convenience, the Company has also included copies of its responses to Division Data Requests Set 1 and Set 2. In connection with the Data Requests, this filing contains a Motion for Protective Treatment of Confidential Information in accordance with 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(A), -(B). National Grid seeks protection from public disclosure of certain confidential and privileged information in Attachment DIV 1-10. In addition, the information in Attachment DIV 1-10 contains Critical Energy Infrastructure Information (CEII). In compliance with Rule 1.3(H), National Grid has provided the PUC with one complete, unredacted copy of Attachment DIV 1-10 in an envelope marked, **"HIGHLY CONFIDENTIAL INFORMATION - DO NOT RELEASE! Contains Critical Energy Infrastructure Information (CEII). Do Not Distribute or Copy".**

The enclosed Plan, which the Company is submitting to the PUC for review and approval, presents an opportunity to continue facilitating and encouraging investment in the Company's electric utility infrastructure and enhance the Company's ability to continue providing safe, reliable, and efficient electric service to customers.

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

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures
cc: John Bell, Division
Greg Booth, Division
Leo Wold, Esq.
Christy Hetherington, Esq.
Al Contente, Division

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Fiscal Year 2021 Electric Infrastructure, Safety and Reliability Plan	))))	Docket No. 4995

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)) and R.I. Gen. Laws § 38-2-2(4)(A), -(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On December 20, 2019, National Grid submitted its Fiscal Year (FY) 2021 Electric Infrastructure, Safety, and Reliability (ISR) Plan filing in the above-captioned docket. In that filing, the Company filed copies of its responses to the Division of Public Utilities and Carriers (Division) First Set and Second Set of Data Requests (Division Data Requests). Division Data Request Division 1-10 requested a copy of the South County East Area Study, which the Company provided as Confidential Attachment DIV1-10. Attachment DIV 1-10 includes one-line diagrams and other information relating to the Company's transmission system, which constitutes Critical Energy Infrastructure Information (CEII) and is protected from public disclosure. Accordingly, the Company is providing both redacted and un-redacted versions of Attachment DIV 1-10.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the confidential CEII contained in Attachment DIV 1-10.

II. LEGAL STANDARD

Rule 1.3(H) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive

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

position of the person from whom the information was obtained. *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47. National Grid meets the first and second prongs of this test, which apply here.

III. BASIS FOR CONFIDENTIALITY

The information contained in Attachment DIV 1-10 should be protected from public disclosure. The information provided in this attachment is confidential and privileged information of the type that National Grid does not ordinarily make public. Attachment DIV 1-10 includes the South County East Area Study, which contains highly sensitive commercial information and trade secrets, such as information relating to the Company's transmission system, and/or CEII.

In addition, public disclosure of the transmission information and other information identified as CEII in Attachment DIV 1-10 would negatively impact National Grid's ability to effectively operate to provide safe and reliable service to its customers. As such, this information is of a kind that National Grid would customarily not release to the public. Therefore, this information satisfies the exception found in R.I. Gen. Laws § 38-2-2(4)(B).

Accordingly, National Grid is providing Attachment DIV 1-10 on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

Jennifer Brooks Hutchinson, Esq. (#6176)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7288
Dated: December 20, 2019

Joint Testimony of
Easterly, Moe & Castro

JOINT PRE-FILED DIRECT TESTIMONY

OF

PATRICIA C. EASTERLY

RYAN A. MOE

KATHY CASTRO

December 20, 2019

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I. INTRODUCTION

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 (PUC)?

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).

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 PUC?

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

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

A. My name is Kathy Castro. My business address is 280 Melrose Street, Providence, RI 02907.

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

A. In 2003, I graduated from Worcester Polytechnic Institute with a Bachelor of Science Degree in Electrical Engineering. In the same year, I was employed by National Grid as an Associate Distribution Design Engineer responsible for design of new facilities for business and capital improvement projects. In 2005 I earned a Graduate level Certificate of Power Systems Management and Engineering from Worcester Polytechnic Institute. In 2005, I joined the Distribution Planning and Engineer department as an Engineer, promoted to Senior Engineer in 2008. In this role, 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 2011, I joined a Consultant Company located in Rockland Massachusetts as a Senior Engineer. In this role, I was responsible for completing distribution system impact analysis of Distributed Generation for Utilities across New England and New York. Within a year I was promoted to Manager of Engineering responsible for building a department which focused on Distribution Planning short and long-term studies. In 2017, I was promoted to Director of Engineering overseeing Distribution Design and Planning functions within the Company. In March of 2018, I assumed my current position as Manager of Distribution Planning and Asset Management.

Q. Have you previously testified before the PUC?

A. Yes. I have previously testified before the Rhode Island Public Utilities Commission in support of the Company's FY2020 ISR plan

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 2021 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 benefit-cost framework (the Framework)[2] that the Public Utilities Commission (PUC) adopted in its Report and Order No. 22851, dated July 31, 2017 and the PUC'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 2021.

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

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

Q. How is the testimony structured?

A. In addition to the Introduction (Section I) and Purpose and Structure of the Testimony (Section II), the testimony includes the following:

- Description of how the Company developed the Electric ISR Plan and FY 2021 capital investment spending levels (Section III);
- Description of the Company's vegetation management program and FY 2021 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 2021 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 2021 (Section VI); and
- Conclusion (Section VII).

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 2021, or the twelve-month fiscal year ending March 31, 2021: 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 2021 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 2021 totaling $103.8 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 identifies thermal capacity constraints, assesses system performance to ensure that the network maintains adequate delivery voltage, 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 for 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 a 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 2 in Section 1 of the Plan provides the current status of annual capacity reviews and the prioritization and status of area planning studies. As shown in Chart 2, the Company has completed 100% of the annual capacity reviews in the eleven study areas. The area study planning process is further described in Section 2 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 does the Company undertake to prepare its capital investment plan for review by the PUC?

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 September 30, 2019 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 reviewed its new estimating processes supporting the complex capital delivery process with the Division. 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 PUC 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 undertook a review of its Damage and Failure spending to address the Division recommendation in Docket 4915 and performed a study of requirements to address increasing Distributed Energy Resources (DER).

To respond to the recommendation on Damage and Failure spending, the Company performed a review of spending in the Damage and Failure category to assess level of spending that did not relate to failure. To align with the Division's recommendation, the Plan reflects, a reduction of $2 million from the Damage and 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.

In addition, 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. For certain transmission faults, additional transmission protection, zero sequence overvoltage or "3V0" protection, is required to prevent DERs from contributing to fault overvoltage conditions. 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 has put forward a plan to invest in more 3VO, 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 of those investments is included within Section 2 of the Plan attached as <u>Exhibit 1</u>.

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 PUC 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.

Q. Please review the FY 2021 capital investment levels.

A. The investment levels proposed for recovery through the Electric ISR Plan for FY 2021 are associated with five key work categories: (1) Customer Request/Public Requirement; (2) Damage Failure (the Non-Discretionary Spending categories of work); (3) Asset Condition; (4) Non-Infrastructure; and (5) System Capacity and Performance (the Discretionary Spending categories of work). The table below summarizes the proposed spending level for each of these key driver categories proposed.

Proposed FY 2021 Capital Investment by Key Driver Category
($000)

Spending Rationale	FY 2021 Proposed Budget	%
Customer Request/Public Requirement	$24,540	23.7%
Damage Failure	$12,365	11.9%
Subtotal Non-Discretionary	$36,905	35.6%
Asset Condition	$31,040	29.9%
Non-Infrastructure	$580	0.6%
System Capacity & Performance	$25,145	24.2%
Subtotal Discretionary	$56,765	54.7%
Asset Condition - Southeast Sub Project	$10,080	9.7%
Subtotal Discretionary	$66,845	64.4%
Total Capital Investment in Systems	**$103,750**	**100%**

As shown in the table above, a significant portion of the investment for capital projects in FY 2021 are necessary to meet customer requests or city, state, and town requirements. (*i.e*. $24.5 million or 23.7 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. 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 $12.4 million, or 11.9 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 $36.9 million or 35.6 percent of proposed capital investment in FY 2021 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 2021 have been chosen to maintain the overall reliability of the system and collectively total approximately $66.8 million, or 64.4 percent of the Company's proposed FY 2021 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 $41.1 million or 29.9 percent (including the Southeast Substation project), of the proposed capital investment in FY 2021. 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 2021 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 $25.1 million, or 24.2 percent, of the proposed capital investment in FY 2021. 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 provide quarterly reports to the Division and the PUC 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 PUC. 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 2021 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 2021, the Company proposes to spend approximately $10.6 million for the Vegetation Management Program. This represents an approximately 0.22 percent increase from the $10.4 million which was approved for FY 2020. The Company is requesting an additional $200,000 to target pockets of poor performance. These are areas which have not been adequately addressed by our routine vegetation management program and require a more prescriptive approach.

V. INSPECTION AND MAINTENANCE PLAN AND OTHER O&M

Q. Please describe the FY 2021 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 $1.0 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 $0.4 million for O&M expenses for the Volt/Var expansion program. The Company proposes a total O&M expense budget of approximately $1.8 million for FY 2021.

VI. <u>DOCKET 4600 BENEFIT-COST FRAMEWORK ANALYSIS</u>

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

A. In Docket No. 4600, Investigation into the Changing Electric Distribution System, the PUC 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 PUC 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) 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 PUC accepted the Stakeholder Report and adopted the goals, principles and new Rhode Island Benefit-Cost Framework

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

(Framework). The Framework includes thirty-four categories of costs and benefits and the PUC 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 PUC and parties to dockets gain more experience applying the Framework. In adopting the Framework, the PUC 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]

Q. Does the PUC's Guidance on "Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid" (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

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

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 FY 2021 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 and Framework to the following new or incremental programs in the Electric ISR Plan: (1) New Lafayette Substation; and (2) DER Enabling Investments. In addition, the Company applied the goals and Framework to incremental spending associated with Hazardous Tree removal for the vegetation management program, as further discussed below.

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

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	New Lafayette Substation	DER Enabling Investments	Vegetation Management
Provide reliable, safe, clean, and affordable energy	Advances	Advances	Advances
Strengthen the Rhode Island economy	Advances	Advances	Advances
Address climate change and other forms of pollution	Advances	Advances	Advances
Prioritize and facilitate increasing customer investment in their facilities	Advances	Advances	Advances
Appropriately compensate distributed energy resources	Neutral	Advances	Neutral
Appropriately charge customers for the cost they impose on the grid	Neutral	Neutral	Neutral
Appropriately compensate the distribution utility for the services it provides	Advances	Advances	Advances
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives	Advances	Advances	Neutral

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 Exhibit 1.

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.

In developing the FY2020 ISR Plan, the Company performed a qualitative assessment only of new or incremental projects or programs. In its filing, the Company noted in the quantitative portion of the assessment that, at the time, the Company did not have an internally-approved, industry-wide accepted methodology to calculate the quantitative value of traditional utility investments. Since then, the Company has made progress on developing a quantitative methodology to calculate the costs and benefits of traditional utility investments. It is important to note, however, that the Company has not adopted this methodology for all utility investments, nor has it been fully vetted with the PUC or stakeholders. The Company has applied this methodology to the FY 2021 Electric ISR Plan to illustrate a possible quantitative assessment under Docket 4600. Notwithstanding this assessment, the Company maintains that for traditional utility infrastructure projects, such as 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.

New Lafayette Substation

Q. Please describe how the Company applied the Framework to the review of the New Lafayette 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 South County East area study. In this case, two alternatives were assessed. The first alternative is the recommended plan, which is to build a new 115/12.47 kV substation at the existing Lafayette substation site consisting of a single 115/12.47 kV 24/32/40 MVA transformer, (4) regulated feeders, and (1) 7.2 MVAr station capacitor bank and retire the 34.5kV supply line which was identified to have significant deterioration on the pole plant and associated equipment. The second alternative is to expand Old Baptist substation by installing a third bay, two additional feeders, and station capacitor banks. This plan would also refurbish the 34.5kV supply to New Lafayette substation.

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 several costs and benefits within each category were not applicable to asset condition/system performance 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 New Lafayette Substation preferred plan yields net benefits of $25,893,649.21 with a benefit-cost ratio of 2.09, whereas the alternative plan yields net benefits of $9,020,791.31 with a benefit-cost ratio of 1.29. See Section 2, Attachment 5 of the Plan. As discussed above, this is the first time the Company has applied the Docket 4600 quantifiable assessment to a traditional utility infrastructure project. For this reason, the Company cautions on relying solely on the benefit-cost ratio, despite its cost-effectiveness. For example, when assessing the distribution system performance benefit at the Power System Level, it was not possible to quantify the impact of not addressing the asset condition issues. Taking no action would leave all the reliability issues unaddressed, which would only worsen over time, thereby adversely affecting customer service and reliability performance.

DER Enabling Investments

Q. Please describe how the Company applied the Framework to the review of the DER Enabling Investments.

A. As discussed above, with the proliferation of DER comes an increasing complexity in managing core compliance obligations such as system load, voltage, and protection systems that are the key to system safety and reliability. To address potential concerns due to specific DER interconnections, the Company is proposing to proactively install required equipment and controls that are needed to enable the interconnection of DER, while allowing the Company to meet its core compliance obligations. As discussed in Section 2 of the Plan, these investments consist of (1) Accelerated 3VO, (2) Mobile 3VO, (3) Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors, and (4) Advanced Recloser Controls.

In applying the Framework, the Company took a similar approach as it did with the New Lafayette Substation. 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. While this program enables the interconnection of DER, it does not directly impact several of the cost and benefit categories within the Power System Level, Customer, Level, and Societal Level. The Company's cumulative analysis for the DER Enabling Investments 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 DER Enabling Investments yield net benefits of $8,790,165.64 with a benefit-cost ratio of 1.70. See Section 2, Attachment 5 of the Plan. In addition to the quantitative assessment, the Company also applied a qualitative assessment. Specifically, when assessing the distribution system performance benefit at the Power System Level, it was not possible to quantify the impact of increased DER on the system. The issues can have location, time, and direction components such that existing infrastructure and control methods will be unable to manage loading, voltage, and protection needs. Load, voltage, and, protection management are fundamental utility compliance requirements for safe and reliable electric service. The proposed program enables the Company to install the distribution line equipment as a first step toward ensuring loading levels, voltage levels, and protection systems are sufficient with various levels of DER penetration. Absent this program, the Company would need to consider additional infrastructure investment or downsizing DER in order to accommodate additional DER interconnections.

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, as illustrated above, 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 Enhanced Hazard Tree Mitigation 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 3, 2019 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 PUC 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 PUC 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 PUC 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.[10] 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.[11]

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

VII. CONCLUSION

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 PUC's approval of the proposed Electric ISR Plan 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 FY2021

The Narragansett Electric Company
d/b/a National Grid

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

December 20, 2019

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

Section 1
Introduction

Section 1

Introduction and Summary
FY 2021 Electric ISR Plan

Section 1: Introduction and Summary

Background

National Grid[1] has developed this proposed Fiscal Year 2021 (FY 2021) 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] The Plan addresses capital spending on electric infrastructure and other costs related to maintaining the safety and reliability of the Company's electric distribution system. The Plan also includes other programs related to safe and reliable service in operation and maintenance (O&M) expenses, primarily for a targeted vegetation management program and an inspection and maintenance (I&M) program.

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. 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

[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.

that arise out of state, municipal, and third-party construction projects. The Company is submitting this Plan to the PUC for final review and approval.[3]

This Introduction and Summary presents an overview of the annual system planning process that leads to the Company Long Range Plan and projects and programs in the ISR; an overview of the proposed FY 2021 Plan for the general categories of costs; a description of how the Company proposes to calculate the revenue requirement associated with the proposed Plan; description of how the Company calculated proposed rates, and customer bill impacts. The Electric ISR Plan describes the Company's proposed electric distribution system safety and reliability activities along with the Company's proposed investments and expenditures contained in the Plan for
FY 2021.

The Company will continue to file quarterly reports with the Division and PUC 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, 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.

The FY 2021 level of spending provided in the Electric ISR Plan to maintain the safety and reliability of the Company's electric delivery infrastructure is $103.8 million of capital

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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 PUC for its review and approval.

investment, $10.6 million of Vegetation Management O&M expense, and $1.5 million of Other O&M expense. The remaining sections of this document will address the annual Plan in more detail. Section 2 contains the Company's proposed capital investment plan for FY 2021. Section 3 contains the Company's proposed VM program. Section 4 contains the Company's proposed I&M spending and other specific programs. Section 5 includes a description of how the Company has calculated the FY 2021 Electric ISR Plan revenue requirement. Section 6 includes the calculation of the proposed rates based on the final revenue requirement consistent with the rate design described below. Finally, Section 7 provides the bill impacts associated with the proposed rates.

System Planning

The Company conducts routine system analyses on its distribution system in the form of annual capacity reviews and area planning studies. A system capacity review is completed on an annual schedule for the entire service territory and identifies thermal capacity constraints, assesses system performance to ensure that the network maintains adequate delivery voltage, and assesses the capability of the network to respond to contingencies that might occur, and achieve the system performance goals for safety and reliability.

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. Other prompts for an area planning study include the identification of asset condition issues, large new customer load request, or acute reliability issues.

The Company has completed 100% of the annual capacity reviews in the eleven study areas. Area planning studies have nine stages of development, which are discussed further in Section 2 of the Plan. The annual capacity review, asset condition evaluations, large customer requests, and reliability reviews inform the prioritization of area planning studies to be completed. The attached table provides the current status of annual capacity reviews and the prioritization and status of area planning studies. The Company has agreed with the Division's recommendation that all new projects are advanced into the ISR after completion by the Company and a review by the Division of area planning studies. Area planning studies typically address issues in a 10- to 15-year window. The next study of an area typically starts 5-7 years after the last study is complete. These dates are subject to change based on annual system assessments that will inform the commencement and prioritization of future studies.

Chart 1
National Grid's Study Areas: Current Priority and Statistics

Rank	Study Area	Load (MVA)	% State Load	# Feeders	# Stations	Annual Planning Review % Complete	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%	50%	Stage 5	Mar-2020	2026
5B	North Central Rhode Island	269	15%	35	10	100%	50%	Stage 5	Mar-2020	2026
6	South County West	98	5%	14	5	100%	20%	Stage 3	Dec-2020	2027
7	Central Rhode Island West	167	9%	33	11	100%	5%	Stage 1	Dec-2020	2027
8	Tiverton	28	2%	4	1	100%	5%	Stage 1	Dec-2020	2027
9	Blackstone Valley South	171	9%	54	11	100%	5%	Stage 1	Dec-2020	2027
10	Newport	105	6%	42	12	100%	0%	NA	Jun-2021	2020
	Totals	**1,845**	**100%**	**385**	**98**	**100%**	60%[i]			

[i] Percent complete based on total state load studied.

Chart 2
Large Projects and associated Area Study

Below are the current projects in the FY2021 ISR that originated from an area study or a study from legacy processes.

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

For new proposals for which funding is requested for the first time, the Company has assessed these proposals using the goals and benefit-cost framework (the Framework)[4] that the Public Utilities Commission (PUC) adopted in its Report and Order No. 22851, dated July 31, 2017 and the PUC'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, This analysis is included in Attachment 5.

Section 2: Electric Capital Investment Plan

The Company's proposed electric capital investment plan included in Section 2 summarizes capital investments by key drivers, describes the development of the capital plan, and outlines the large programs and projects contained in the Plan. Regarding the ratemaking

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

treatment of capital spending, the Company proposes that capital investments used for establishing rates for FY 2021 be those investments in electric distribution infrastructure assets that the Company anticipates will be placed into service during the fiscal year. Projects are advanced out of the area planning studies and included in the Company's Long Range Plan. Based on prioritization and need date, projects are included in the Company's capital forecast and proposed for inclusion in the Company's annual ISR Plan. The Company also progresses programs into its Long Range Plan and includes one year of those programs as part of the FY 2021 Electric ISR Plan.

Section 3: Vegetation Management

Section 3 contains the Company's Vegetation Management program and proposed expenses for FY 2021, a discussion of the nature of the work, and the expected benefits of such work.

Section 4: I&M Plan & Other O&M

Section 4 contains the Company's I&M and Other O&M expense for FY2021, a discussion of the nature of the work, and the expected benefits.

Section 5: Electric Revenue Requirement

Section 5 provides a calculation of the cumulative revenue requirement resulting from the proposed FY 2021 capital investment plan and the total annual vegetation management, I&M and other O&M program expenses. This section includes a description of the revenue requirement model that will be used to support the final revenue requirement. The calculation includes the pre-tax rate of return on rate base approved by the PUC in Docket No. 4770, the Company's last general rate case.

Section 6: Rate Design and Rates

Once the revenue requirement is calculated, it is allocated to rate classes based upon the most recent rate base allocator approved in the Amended Settlement Agreement in Docket No. 4770.

Section 7: Bill Impacts

Section 7 provides the estimated typical bill impacts associated with the rate design and proposed rates.

Section 2

Electric Capital Investment Plan
FY 2021 Electric ISR Plan

Section 2: Electric Capital Investment Plan

Background

The Company developed its proposed Electric ISR Plan to meet its obligation to provide safe, reliable, and efficient electric service for customers at reasonable costs.[5] The Plan includes 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 or migration; (4) maintain reliable service; and (5) sustain asset viability through targeted investments driven primarily by asset condition.

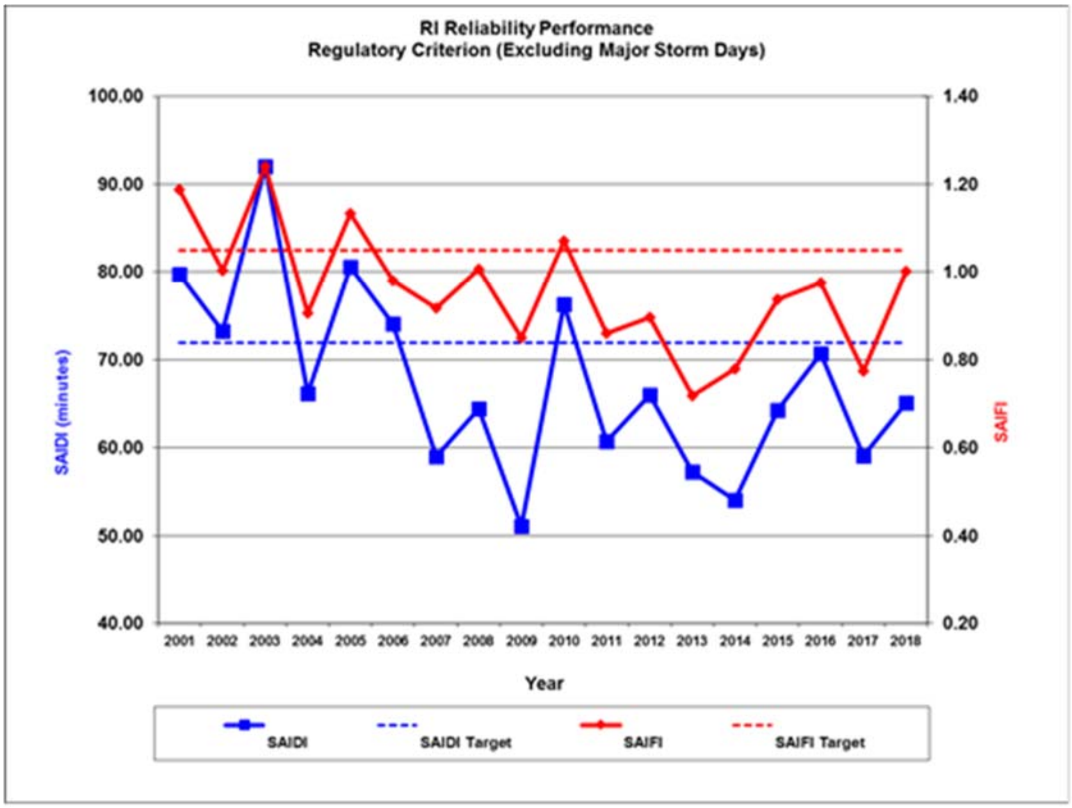
Since the inception of the ISR in FY 2012, the Company has consistently met its system reliability goals. As shown below in Chart 3 below, the Company met both its calendar year (CY) System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2018, with SAIFI of 1.001 against a target of 1.05, and SAIDI of 65.11 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days.[6] Performance has shown an

[5] As of March 28, 2019, the Company delivers electricity to 496,808 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 5,116 miles of overhead and 1,112 miles of underground distribution and sub-transmission circuit in a network that includes 88 sub-transmission lines and 391 distribution feeders. The Company relies on 65 distribution substations that house 121 power transformers and 858 substation circuit breakers to deliver power to its customers. The Company's electric delivery assets also include 282,416 distribution poles, 4,553 manholes, and 66,485 overhead (pole-mounted) and underground (pad-mounted or in vault) transformers.

[6] A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (4.49 minutes for CY 2018). 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.

improving downward trend over the past several years with major event days excluded. See Attachment 6 for further detail related to system performance reliability data.

Chart 3
RI Reliability Performance CY 2001 – CY 2018
Regulatory Criteria (Excluding Major Event Days)



System Planning

Before developing the annual ISR Plan, the Company conducts routine system analyses on its distribution system in the form of capacity reviews and area planning studies.

The Company capacity review is completed on an annual schedule and identifies thermal capacity constraints, assesses system performance to ensure that the network maintains adequate delivery voltage, and assesses the capability of the network to respond to contingencies that might occur. The capacity planning process includes the following tasks:

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

When capacity reviews highlight an area that has capacity constraints of a level where a detailed and comprehensive analysis is warranted, that area is identified as needing an area planning study. Additional detail related to the system capacity review process is included in the System Capacity and Performance portion of this section, below. Other prompts for an area planning study include the identification of asset condition issues, a large new customer load request, or acute reliability issues. Completion of this assessment process is also known as an annual planning review.

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 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 / Engineering Analysis;

- **Stage 5:** Development and Project Estimating of alternative infrastructure and non-wires alternative plans;

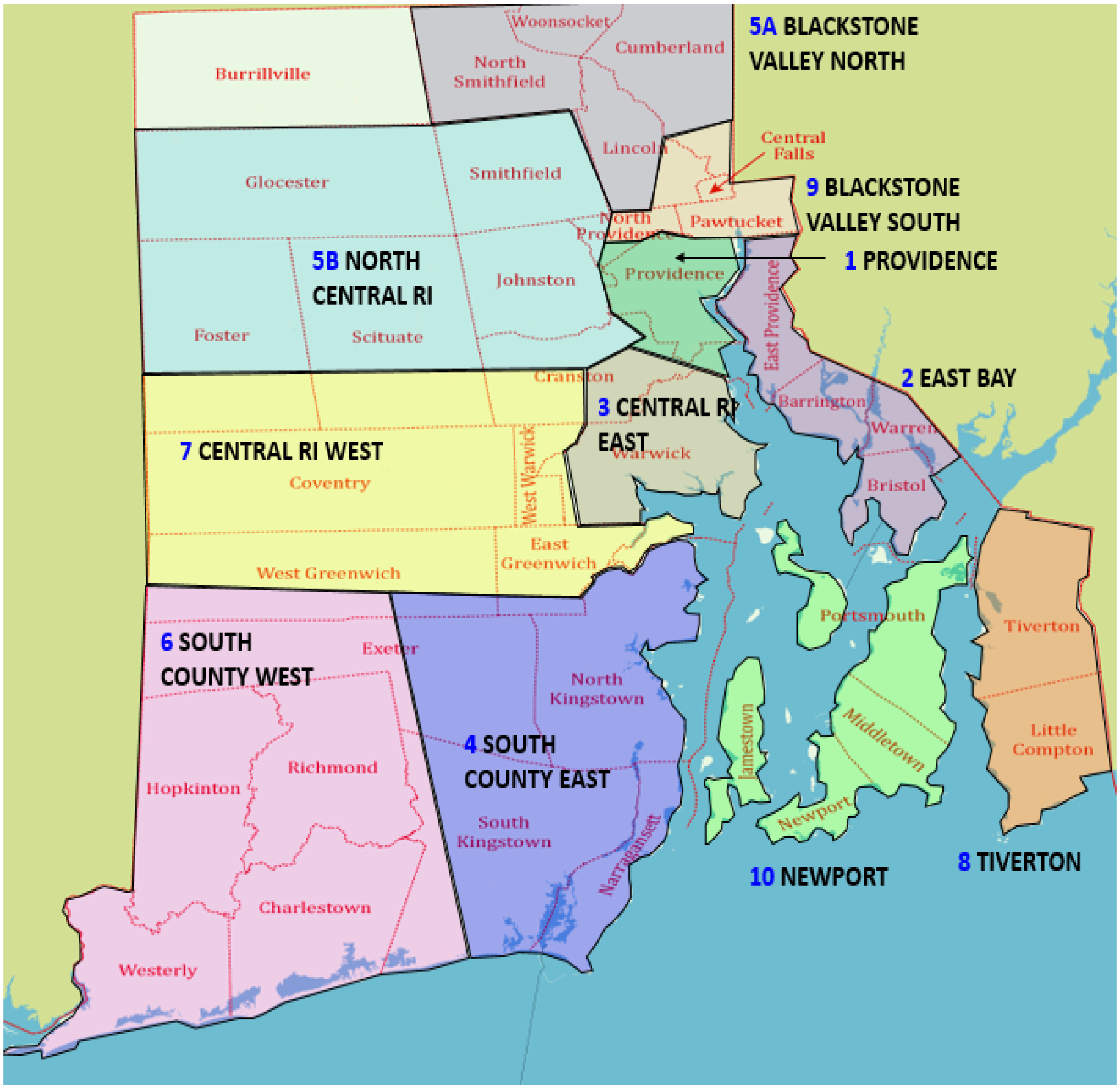
- **Stage 6:** Review of various alternatives' relative costs and benefits, and identifying and finalizing a recommended plan;

- **Stage 7:** Technical Review presentation with approval committee;

- **Stage 8:** Delivery of area study report documentation upon completion of the study;

- **Stage 9:** Sanction of any recommended projects having forecasted spending within the next three fiscal years.

Chart 4 - Annual Planning Review Status



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 (resolved, substation retired), Contingency issues at Kent County. (resolved), Asset, flood risk, & environmental concerns at Hunt River (resolved, substation retired), 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. (solution in progress), Asset condition concerns at Pawtucket No 2 Indoor substation, Normal and contingency capacity issues at Pawtucket No 1. (pending solution)
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. (solution in progress), Asset condition concerns at Vernon & Bailey Brook (solution in progress), Subtransmission capacity concerns (solution in progress)
Resolutions: On-going area reconfiguration and new substations (Newport and rebuilt Jepson) should address most issues in area, Any remaining concerns will be reviewed in a to be kicked off area study after existing conversion and rebuild is complete.

During the Development and Project Estimating stage (Stage 5, above), Engineers screen projects for non-wires alternatives (NWA). NWA screening is based on criteria defined in Docket 4684 – The Narragansett Electric Company, d/b/a National Grid 2018-2020 Energy Efficiency and System Reliability Procurement Plan (SRP). The Company submitted this 3-year plan in compliance with the R.I. Gen. Laws § 39-1-27.7 and the revised Least Cost Procurement Standards (Standards). The Company considers all alternatives in order to identify the least cost option.

Identified electric distribution system needs that meet the following criteria will be evaluated for potential NWAs that could reduce, avoid or defer a T&D wires solution over an identified time period.

- The need is not based on asset condition;
- The wires solution, based on engineering judgment, will likely cost more than approximately $1 million; the cost floors may vary across different project types and time frames;
- If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area, or sub area in the event of a partial solution, of the defined need;
- Start of wires alternative construction is at least 30 months in the future;
- At its discretion, the Company may consider and, if appropriate, propose a project that does not pass one or more of these criteria if it has reason to believe that a viable NWA solution exists, assuming the benefits of doing so justify the costs.

NWAs are progressed for regulatory review and funding through the Company’s SRP Plan. There are no investments within the FY2021 ISR plan that have an overlapping NWA being progressed through the SRP Plan.

FY 2021 Capital Investment Plan

As shown in Chart 5 below, the Company plans to invest $103.8 million in FY 2021 to maintain the safety and reliability of its electric delivery infrastructure. Chart 6 shows the same information in tabular form. This spending level is approximately two percent higher than the Company's approved FY 2020 Electric ISR Plan of $101.8 million.

Chart 5
Capital Spend by Category FY 2010 – FY 2021

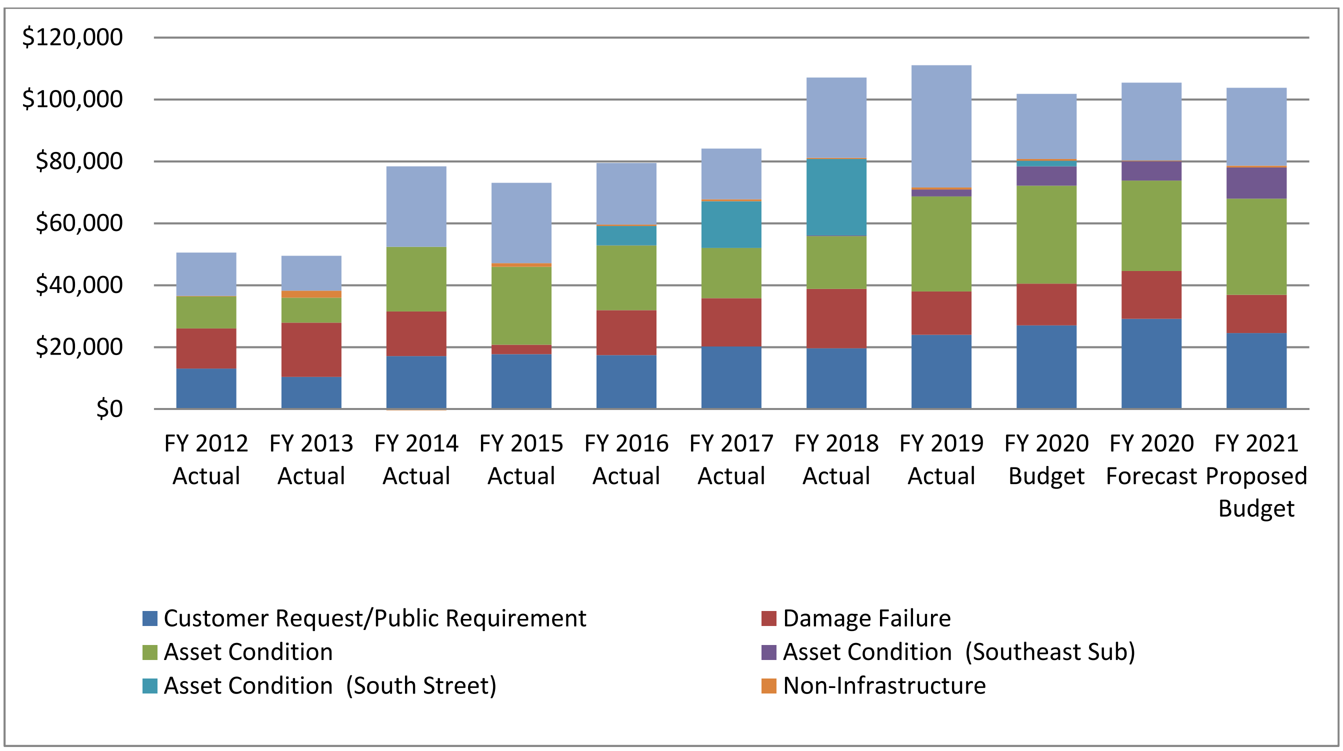


Chart 6
Capital Spend by Category FY 2012 – FY 2021
($000)

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 Budget	FY 2020 Forecast	FY 2021 Proposed Budget
Customer Request/Public Requirement	$13,075	$10,410	$17,138	$17,760	$17,412	$20,233	$19,627	$23,989	$27,025	$29,148	$24,540
Damage Failure	$12,993	$17,515	$14,374	$3,044	$14,531	$15,614	$19,184	$13,999	$13,505	$15,463	$12,365
Asset Condition	$10,320	$8,071	$20,905	$25,141	$20,877	$16,204	$17,074	$30,708	$31,625	$29,194	$31,040
Asset Condition (Southeast Sub)	$0	$0	$0	$0	$74	$0	$167	$2,188	$6,250	$6,256	$10,080
Asset Condition (South Street)	$0	$0	$0	$0	$6,228	$15,070	$24,737	$0	$1,800	$0	$0
Non-Infrastructure	$149	$2,269	($346)	$1,216	$457	$622	$363	$673	$550	$204	$580
System Capacity & Performance	$13,995	$11,249	$25,972	$25,890	$19,920	$16,371	$25,906	$39,515	$21,045	$25,135	$25,145
Total Capital Investment in Systems	**$50,532**	**$49,514**	**$78,043**	**$73,051**	**$79,499**	**$84,114**	**$107,058**	**$111,072**	**$101,800**	**$105,401**	**$103,750**

Since a portion of the proposed capital spending in FY 2021 is for projects that will be completed over multiple years, the Company anticipates that only part of that spending will be placed in service in FY 2021. Likewise, a portion of the capital to be placed in service in FY 2021 will also reflect the capital spending for similar multiyear projects that commenced in prior years.

On August 14, 2019, the Company met with the Division's consultants regarding the proposed FY 2021 Electric ISR Plan spending categories and budgets. During that meeting, the Company provided additional detailed information on major multi-year projects included in the FY 2021 Plan. Attachment 4 includes a summary of information regarding these major multi-year projects . This information may vary slightly from certain previous information the Company provided to the Division because the Company continues to refine the project cash flows based on the best information available throughout the development of the Electric ISR Plan filing to be filed with the Commission.

Chart 7 below provides actual and forecasted Plant-in-Service dating back to FY 2012 (when the Electric ISR Plan was first implemented) through the proposed FY 2021 Plan.

Chart 7
Plant-In-Service FY 2012 – FY 2021
($000)

`	Plant-in-Service										
	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 Target**	**FY 2020 Forecast**	**FY 2021 Proposed**
Customer Request/Public Requirement	$15,144	$11,262	$13,845	$18,443	$19,594	$14,959	$20,825	$24,011	$20,053	$21,373	$21,210
Damage Failure	$13,628	$12,173	$16,928	$3,804	$16,371	$13,635	$15,085	$16,172	$13,568	$13,577	$12,335
Asset Condition	$13,019	$6,638	$14,640	$28,094	$18,533	$18,726	$44,645	$36,599	$28,008	$29,135	$38,948
Non-Infrastructure	$60	$113	$1,990	$346	$111	$0	$3	$0	$553	$439	$566
System Capacity & Performance	$9,799	$14,145	$8,727	$25,970	$16,845	$28,170	$12,103	$34,461	$40,615	$34,169	$37,435
Total Plant-in-Service	**$51,650**	**$44,331**	**$56,130**	**$76,657**	**$71,453**	**$75,489**	**$92,660**	**$111,243**	**$102,797**	**$98,693**	**$110,494**

Summary of Investment Plan by Key Driver

Chart 8 below summarizes the planned spending level for each of the key driver categories of the Electric ISR Plan proposed for FY 2021.

Chart 8
Proposed FY 2021 Capital Spending by Key Driver Category
($000)

Spending Rationale	Proposed Budget	%
Customer Request/Public Requirement	$24,540	23.7%
Damage Failure	$12,365	11.9%
Subtotal Non-Discretionary	$36,905	35.6%
Asset Condition	$31,040	29.9%
Non-Infrastructure	$580	0.6%
System Capacity & Performance	$25,145	24.2%
Subtotal Discretionary	$56,765	54.7%
Asset Condition - Southeast Sub Project	$10,080	9.7%
Subtotal Discretionary	$66,845	64.4%
Total Capital Investment in Systems	**$103,750**	**100%**

As shown above in Chart 8, approximately $24.5 million, or 23.7 percent of the spending for capital projects in FY 2021, is necessary to meet customer requests and public requirements. These investments arise from the Company's regulatory, governmental, or contractual obligations, such as responding to new customer service requests, including customer Distributive Generation (DG) requests; transformer and meter purchases and installations; outdoor lighting requests and service; and facility relocations related to public works projects requested by cities and towns and the Rhode Island Department of Transportation (RIDOT). Overall, the scope and timing of this work is defined by those who are external to the Company.

The amounts required to immediately repair failed and damaged equipment totals approximately $12.4 million, or 11.9 percent, of the Company's proposed capital investment in FY 2021. 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.

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 $36.9 million, or 35.6 percent of the proposed capital investment in FY 2021.

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 reliability, asset condition, and non-infrastructure projects that the Company will pursue in FY 2021 have been chosen to minimize the likelihood of reliability issues and other problems due to under investment in the overall system.

The Company also has minimal discretion to address load constraints caused by the existing and growing and/or shifting demands of customers. Investments to address these issues account for approximately $15.4 million, or 61 percent of the investment dollars categorized as system capacity and performance. These investments are required to ensure that the electric network has sufficient capacity to meet the existing and growing and/or shifting 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.

Investments that are required to maintain reliable service to customers accounted for $9.7 million of the system capacity and performance category, or 39 percent of the total proposed category capital budget in FY 2021. This category includes investment to improve the overall performance of the network.

Projects necessary based on the condition of the infrastructure assets account for approximately $41.1 million, or 39.6 percent of the proposed capital spending in FY 2021. The Southeast Substation project[7] accounts for $10 million, or approximately 24.5 percent of the proposed capital spending in the Asset Condition category for FY 2021. These projects have been identified to reduce the risk and consequences of unplanned asset failures based on their present condition. The focus of the asset condition 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 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

[7] The Company and Division have agreed to separately track the Southeast Substation project and report on its progress beginning in the FY 2020 Electric ISR quarterly reports.

such equipment. The investments made in these assets are prioritized based on their likelihood of failure along with consequences of such an event.

The non-infrastructure category of investment is for those capital expenditures that do not fit into one of the above-mentioned categories, but which are necessary to run the electric system, such as general and telecommunications equipment. In total, capital spending for non-infrastructure projects will account for $0.6 million, which is 0.6 percent of the proposed capital budget in FY 2021.

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. Together, these items total approximately $66.8 million, or 64.4 percent of the proposed capital investment in FY 2021.

Development of the Annual Work Plan

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 programs and individual capital projects. Programs and projects are categorized by the following spending categories: Customer Requests/Public Requirements, Damage/Failure, System Capacity and Performance, Non-Infrastructure, and Asset Condition. The proposed spending forecasts for each program or project include the latest cost estimates for in-progress projects and initial estimates for newly proposed projects.

Once the mandatory budget level has been established for the Customer Request/Public Requirements and Damage/Failure spending rationales, the Company reviews programs and projects in the other categories (i.e., System Capacity and Performance and Asset Condition spending rationales) for inclusion in the spending plan. A risk score is assigned to each project based upon the estimated probability that a system event will occur and the consequences of the event, including the impact on customers and the public. The project risk score takes into account key performance areas such as safety, reliability, and environmental, while also accounting for criticality. Plan inclusion/exclusion for any given project is based on several different factors, including, but not limited to: new project or in-progress status, risk score, scalability, and resource availability. In addition, when it can be accomplished, the bundling of work and/or projects is analyzed to optimize the total cost 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 by spending rationale to identify any 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.

The capital plan for FY 2021 presented in this Plan represents 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. As described above, some of the projects are already in-progress or will soon be in-progress. Estimates for those projects are quite refined. Other projects are at earlier stages in the project evolution process. The budgets for those projects are, accordingly, less refined and are more susceptible to change.[8] The Company is striving to have estimates after detailed design for many, if not all, of the projects that require construction in the upcoming fiscal year. The Company continuously reviews the capital plan during the year for changes in assumptions, constraints, project delays, accelerations, outage coordination, permitting/licensing/agency approvals, system operations, performance, safety, updated estimates, and customer-driven needs that may arise. Based on those changes, the capital plan is updated throughout the current year.

As stated above, the result of the budgeting process is the approval of a total dollar amount for capital spending in the budget year. In addition to this planning and budgeting process, specific approval must be obtained for any strategy, program, or project within the capital plan. Approval is obtained through a Delegation of Authority (DOA) requirement prior to proceeding with project work, including engineering and construction. Each project must receive the appropriate level of management authorization prior to the start of any work. Approval authority is administered in accordance with the Company's DOA governance policy, with projects over $1.0 million requiring a Project Sanction Paper (PSP). For complex projects (a project with a complexity score of 19 or greater), the Project Development group writes the

[8] Associated with the new complex capital delivery process, the Company is aiming for complex projects to come out of an Area Study with an estimate of +50%/-25% and will go through a stage-gate process that will develop a risk-assessed estimate. The DOA for projects will be done at +/- 10%.

PSP. For non-complex projects (a project with a complexity score of 18 or lower), the project sponsor writes the PSP.

A PSP includes details regarding many aspects of the project including:

- Project background, description, and drivers
- Business issues and the analysis of alternative courses of action
- Cost analysis of the proposed project
- Project schedule, milestones, and implementation plan

Once an approved project (greater than $1.0 million) is completed, the project manager is responsible for preparing closure papers, which includes information on a number of factors, including a discussion of whether, and to what extent, project deliverables were achieved and lessons learned as a result of project implementation.

Projects under $1.0 million are authorized online, and the project sponsor must provide relevant information regarding the cost and justification of the proposed project.

Capital projects are authorized for all construction costs following preliminary and final engineering. Reauthorization is required if the Company expects project costs to exceed the approved estimate plus an approved variance range identified in the project spending plan. Any reauthorization request must include the original authorized amount, the variance amount, the reasons for the variance, the details and costs of the variance drivers, and the estimated impact on the current year's spending. On a monthly basis, the project and program management groups monitor project spending against authorized levels. The project and program management groups also review on a monthly basis exception reports covering actual or forecasted project spending greater than authorized amounts.

The Company includes certain reserve line items in its spending plan by budget category, to allocate funds for projects whose scope and timing have not yet been determined. In some cases, historical trends are used to develop the appropriate reserve levels, especially reserves related to non-discretionary categories that will address emergent, customer or generator requirements, damaged or failed equipment, or regulatory mandates. The Company manages budgetary reserves and emergent projects within the overall budget as part of its investment planning and current year spending management processes. There are no discretionary reserves in the FY 2021 proposed budget. The discretionary reserves in FY 2022 and beyond will be replaced with specific projects as the Long Term Studies and other tactical initiatives are progressed.

Description of Large Programs and Projects

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 8 above. Attachment 2 contains a more detailed breakdown of the spending totals by project to the extent that such detail is available.

Customer Request/Public Requirements

As shown in Attachment 1, the Company has set a budget of $24.5 million to meet its Customer Request/Public requirements in FY 2021. This is approximately 9 percent lower than the FY 2020 budget of $27.0 million.

Approximately 52 percent of the Customer Request/Public Requirement budget is required to establish electric delivery service to new commercial and residential customers. The Company currently expects to spend approximately $12.8 million for this category of work in FY 2021. Importantly, the actual and proposed spending in this category is net of contributions in aid of construction (CIAC) that are received from customers.

Approximately 11 percent of the Customer Request/Public Requirement budget is required for public projects. The Company currently expects to spend approximately $2.7 million for this category of work in FY 2021. The following projects are included in this category:

- Relocating/adding company assets due to road or bridge-work
- Moving assets such as poles to accommodate a new driveway or other similar customer requests
- Construction as requested by the telephone company, public authorities, towns, municipalities, RIDOT, and other similar entities
- Required environmental expenditures

Finally, since much of the construction work in the customer requests and public requirements category is variable and requested on short notice, to account for emergent projects, the Company sets budget reserves for the work under this category based on data from previous fiscal years. Since the Company is reimbursed for a portion of this spending, the budget reserves represent the capital the Company expects to spend, net of CIACs and other reimbursements. Additional information on specific projects for this category is included in Attachment 2.

Damage/Failure

For FY 2021, the Company is proposing a $12.4 million budget for non-discretionary costs to replace equipment that either unexpectedly fails or becomes damaged. In response to a recommendation made by the Division related to its review of the FY2020 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, which the Company believes may reduce the Damage/Failure blanket work. Therefore, the Company made a $2 million reduction to this budget over the budget for FY 2020 following this review. Offsetting that reduction is an increase of $0.7 million due to replacing a specific transformer that failed during FY2020. Because the work in this category is unplanned by nature, the Company sets this budget based on multi-year historic 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 complete until FY 2021. As in FY 2020, the budget set for FY 2021 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.

There are four major components of the Damage/Failure portion of the Company's capital plan:

- *Damage/Failure Blanket Projects* – These projects are for substation and/or line failures or those assets whose size is unknown at the time of the failure. Currently, the Company expects to spend approximately $9.0 million for this category of work in FY 2021.

- *Damage/Failure Reserve for Specific Projects* – This is a reserve to address larger failures that require capital expenditures in excess of $100,000. The reserve is built on recent historic trends of such items and allows the Company to complete unplanned work without having to halt work on projects that are planned to stay on target with the overall capital budget. Currently, the Company expects to spend approximately $1.0 million for this category of work in FY 2021.

- *Damage/Failure for Sockanosett Transformer* - The Sockanosett transformer failed during FY2020 and the FY2021 budget reflects the remaining costs to replace this transformer of $0.7 million.

- *Major Storms* – Each year, the Company carries a budgeted project for major storm activity that affects the Company's assets. While the actual spend in this category may vary greatly, this reserve, based on average trends over the past several years, allows the Company to avoid removing other planned work from the capital program when replacement of assets due to weather is required. Currently, the Company expects to spend approximately $1.7 million for this category of work in FY 2021.

Asset Condition

The Company is proposing a $41.1 million budget for FY 2021 to replace assets that must be replaced to maintain reliability performance. This level is approximately 4 percent higher than the $39.7 million budget for FY 2020 and is primarily driven by the $10 million for the Southeast Substation project and $7.2 million for the Dyer Street substation replacement project.

Attachment 3 contains charts illustrating the current age profiles for distribution poles, distribution service transformers, metalclad substations, substation batteries, substation power transformers, and substation breakers and reclosers. Age is not a perfect indicator of asset condition, and, in general, the Company makes asset replacement decisions factoring in asset condition, rather than asset age. Nonetheless, reviewing asset age is a method for demonstrating how current spending levels are improving or maintaining overall asset condition.

The key asset condition budget categories are as follows:

- *Admiral Street* – The Providence Area 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 Company proposes capital spending of approximately $4.2 million on this project in FY 2021.
- *Dyer Street Replace Indoor Substation* – The purpose of this project is to replace the existing indoor substation at Dyer Street. In FY 2021, the Company proposes capital spending of approximately $7.2 million to finalize the design, purchase materials and start construction. As shown in Attachment 4, this is another multi-year project with capital spending in future fiscal years.
- *Southeast Substation* – The Company and the Division have agreed to track this project separately and report on its progress in the FY 2021 Electric ISR quarterly reports. This project is required to address asset condition concerns at the Pawtucket No. 1 substation. The Pawtucket No. 1 substation consists of a four-story brick building that was constructed in 1907 and includes an indoor substation and an outdoor switchyard. In addition to structural issues with the building, the indoor substation includes breakers and

relays with condition issues and structures with clearance issues. Electrically, Pawtucket No. 1 station is located on the west side of the Seekonk River and serves half of its load in this area. The other half of the Pawtucket No. 1 load is located on the east side of the river. While the asset conditions indicate the need for a station rebuild of Pawtucket No. 1, the Southeast station site (also known as Dunnell Park Substation), located on the east side of the river, creates an opportunity to split the load, improve overall capacity, and avoid the capacity and operational constraints created by the river. As shown in Attachment 4, this is a significant multi-year project. The Company anticipates capital spending in FY 2021 of approximately $10.1 million to progress construction activities.

- *Inspection & Maintenance Program* – This program has both capital and O&M components. The proposed capital spending for I&M in FY 2021 is approximately $2.9 million. Section 4 includes additional details regarding the capital and O&M components of the I&M program.
- *The Substation Circuit Breaker and Recloser Strategy and Program* – This program targets obsolete and unreliable breaker facilities. The Company has approximately 1,038 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. The Company proposes capital spending of approximately $1.3 million on this project in FY 2021.

- *Recloser Replacement Strategy and Program* – The purpose of this program is to address multiple issues and concerns with 38 in-service Form 3A reclosers. The issues relate to operations, maintenance, safety, reliability, and asset condition. These units have been in service for more than 25 years and are exhibiting a variety of problems, all of which have caused multiple malfunctions, including but not limited to, battery charging problems, battery failure, and exterior deterioration/rust. Each location will be individually studied to develop the most cost-effective solution for the replacement, which may require one for one replacement, one for many replacements, relocation, and/or elimination. A coordination analysis of the entire circuit will be reviewed and optimized. The Company developed a criticality model to prioritize replacements and proposes to spend $0.5 million in FY 2021.
- *Underground Cable Strategy* – The goal of this strategy is to replace primary underground cable that is either in poor condition or has a poor operating history. 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 rationale based on type of construction, asset condition, and failure history for a specific or similar asset. Reactive fix-on-failure replacement, which the Company considers mandatory spending, often evolves into proactive replacement of an entire circuit or a localized portion of a circuit, which is considered discretionary spending. Discretionary spending for proactive replacement can be further categorized by that work justified by the need to eliminate repeated in-service failures, work justified by anticipated end-of-life based on historic performance or

industry experience, and work made necessary by other operational issues. Candidate projects are reviewed and re-prioritized throughout the year as required by changing system needs and events. Examples of distribution cables currently being planned for replacement include the 79F1, 79F2, and 2J8 primary circuits, and portions of the network secondary cable system. The Company proposes capital spending of approximately $4.5 million on this project in FY 2021.

- *URD Cable Strategy* – 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. It sets forth the approach for replacing or rehabilitating (through cable injection) these cables. 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 addressing repeated failures: cable rehabilitation through insulation injection or cable 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. The Company proposes capital spending of approximately $4.0 million on this project in FY 2021.

- *Network Blower Motor Program* – This program replaces network vault blower motors with arc resistant motors. Approximately 100 network vault blower motors exist in the Rhode Island electric system predominantly located in Pawtucket and Providence. Approximately 25 motors sites will require additional civil work to increase exhaust ducts and additional wiring work. The Company proposes capital spending of approximately $0.4 million on this project in FY 2021.
- *Strategy to Replace Distribution Substation Batteries* – The Company has more than 117 battery systems in its distribution substations, and these systems play a significant role in the safe and reliable operation of substations. The batteries and chargers in these systems 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. One goal of the Company's strategy is to replace batteries that are 20 years or older. Another goal is to ensure that battery systems meet the current operating requirements and perform their designed functions. The Company proposes capital spending of approximately $0.2 million on this project in FY 2021.
- *Blanket Projects* – In addition to specific projects, the Company also has asset replacement blanket projects that were established to ensure that a mechanism is in place to initiate, monitor, and report on work under $100,000 in value. 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. The current year spending in the project is monitored on a monthly basis. The blankets provide local field engineering and

operations with the control accounts to facilitate timely resolution of asset condition issues (i.e., deteriorated equipment). The Company proposes capital spending of approximately $3.5 million on this project in FY 2021.

System Capacity and Performance

For FY 2021, the Company is proposing a $25.1 million budget for System Capacity and Performance projects, which is 20 percent higher than the FY 2020 budget of $21 million. This increase is driven primarily by the Strategic DER Advancement investments, discussed below, First Street (East Providence) substation, and New Lafayette substation projects. The System Capacity and Performance category includes Load Relief and Reliability projects. The Load Relief projects account for $15.4 million or 61 percent of the proposed System Capacity and Performance spending in FY 2021. The remaining 39 percent is made up of Reliability projects, which have a proposed FY 2021 spending budget of $9.7 million.

To identify the need for capacity expansion projects, the Company has developed a multi-step, top down/bottom up process to forecast the loading on these assets. First, the Company uses an econometric model to forecast summer and winter peak loads. The explanatory variables in this model include historical and forecasted economic conditions at the county level,[9] historical peak load data, and a forecast of weather conditions based on historical data from several weather stations.

[9] This data and forecasts are provided by Moody's Economy.com.

The Company uses this model to simulate the historical and forecasted peak demand for areas of 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 a given set of economic conditions. Based on the historical experience, there is a 5 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 the energy efficiency (EE) and solar-photovoltaics (PV) savings achieved through 2018 since these savings would be reflected in the historical data used by the model. The Company subtracts forecasted incremental EE and PV savings beyond the amounts achieved through 2018 from the load forecast.

The growth rates 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.

The Company has developed guidelines for the consideration of non-wires alternatives in the distribution planning process. 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. As part of this process, the Company conducts analyses at a level of detail commensurate with the scale of the problems and the cost of potential solutions.

Some of the most significant Load Relief Projects for FY 2021 are described below. It is also important to recognize that these projects also have asset condition drivers that also drive replacement decisions.

- *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. The Aquidneck Island Projects proposed budget for FY 2021 is $13.5 million. Below are details on the projects with proposed spending in FY 2021.
    - *Newport Substation:* This project will involve the construction of a new 69/13.8 kV substation and all related distribution line work to develop five new 13.8 kV feeders to provide load relief to the City of Newport. The completion of this project will provide thermal relief to overloaded feeders and supply lines in the City of Newport and improve the overall reliability to Aquidneck Island. The installation of new 13.8 kV feeders and conversion of 4 kV load to the new station improves the reliability of the 23 kV supply and 13.8 kV distribution systems

during contingencies. This Plan supports the retirement of Bailey Brook and Vernon substations to address reliability, asset condition and environmental concerns with the most economical solution. The Company proposes to spend approximately $5.9 million on this project in FY 2021.

  - *Jepson Substation:* This project will involve rebuilding the existing substation in Middletown, RI (Jepson Substation). The substation rebuild will include two power transformers supplying six 13.8 kV feeders and two power transformers supplying three 23 kV supply lines. The Company proposes to spend $6.9 million on this project in FY 2021.

- *East Providence Substation:* The East Bay Long Term Study identified several 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, also known as First Street, in the city of East Providence on a gas company-owned land parcel adjacent to the 115 kV transmission right-of-way. Initial construction would consist of a single 40 MVA LTC transformer, straight-bus metal-clad switchgear, four feeder positions, and a 7.2 MVAR two-stage capacitor bank. The ultimate build-out would be two 40 MVA LTC transformers supplying straight-bus metal-clad switchgear with a tie breaker, eight feeder positions, and two 7.2 MVAR two-stage capacitor banks. The Company proposes to spend approximately $1.6 million to progress preliminary engineering and procurement on this project in FY 2021.

- *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 to spend approximately $0.5 million to progress preliminary engineering in FY 2021.
- *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. The Company proposes to spend approximately $0.4 million to progress preliminary engineering in FY 2021.
- *Blanket projects:* In addition to specific projects, the Company also has three blanket projects that were established to ensure that a mechanism is in place to initiate, monitor, and report on work under $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, and a forecasted impact of inflation on material and labor rates. Spending in the project is

monitored on a monthly basis. The substation and line load relief blankets provide O&M services and local field engineering with the control accounts to facilitate timely resolution of system and equipment loading and reliability issues, such as overloaded sections of wire/cable or step-down transformers, the installation of feeder voltage regulators and capacitors, and minor work to facilitate the reallocation of load on existing circuits. The reliability blanket also provides local field engineering with the control accounts to facilitate timely resolution of historical and new reliability issues that emerge. Budgeted spending for the blanket projects is approximately $1.4 million in FY 2021.

- *Substation 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. The Company proposes to spend approximately $1.0 million for this program in FY 2021.
- *Volt/VAR Optimization and Conservation Voltage Reduction (VVO/CVR) Expansion*: 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. The Company believes that this will benefit customers by reducing the demand and energy usage through CVR.

  The Company has historically managed the voltage profile of distribution feeders using substation transformer load tap changers, voltage regulators, and capacitor banks with independent, locally based, conservatively programmed controls. Therefore, the Company is generally able to keep the range of voltages provided to customers along the circuit within the required +/- 5 percent ANSI range. This results in a default voltage profile which is high at the substation, and near the low-range at the end of line under heavy loads.

VVO refers to the process of more intelligently using distribution capacitors and regulators in a coordinated manner to flatten the voltage profile based on real time system performance. Once the profile is flattened, the controller can then lower the voltage coming from the substation to drop the voltage to the entire distribution circuit to be closer to the lower end of the ANSI range. By reducing the service voltage, the mix of loads for those customers will operate more efficiently and use less energy. This effect is called CVR.

The Company believes that this technology should be further expanded. Using lessons learned from the Putnam Pike and Tower Hill pilot projects and the existing back office infrastructure, the Company will expand this project to four additional areas-that have recently undergone distribution studies and have circuit and load characteristics that provide the highest value for the service territory. The Volt/Var project will have ongoing O&M costs for maintaining network and telecommunications components, servers, hardware, and software licensing. In FY 2021, the Company proposes to continue this expansion, with an anticipated spend of approximately $1.1 million in capital and $0.4 million in O&M costs.

- *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, National Grid is developing a proactive 3V0 program, the intent of which is to install 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. In FY 2021, the Company proposes to spend approximately $0.5 million to continue this program.

- *Strategic DER Advancement:* To more readily be able to respond to Distributed Energy Resources (DER) interconnections, several targeted investments are being proposed within the FY 2021 ISR plan that would contribute to maintaining system compliance while advancing State and Company decarbonization goals.

  The investments include (1) Accelerated 3V0, (2) Mobile 3V0, (3) Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors, and (4) Advanced Recloser Controls. 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.

  In FY 2021, the Company proposes to spend approximately $3.7 million towards these investments.

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

The Company calculates the revenue requirement based on the Company's 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 2021. 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 in April 2011. 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.

Charts 9 below provides details regarding the total FY 2021 proposed amounts for Capital Spending, Capital Placed-in-Service, and COR that have been used to develop the FY 2021 Electric ISR Plan revenue requirement.

Chart 9
Proposed FY 2021 Proposed Capital Spending, Plant-in-Service, and COR
($000)

Spending Rationale	Capital Spending	Capital Placed-in-Service	COR	Capital Placed-in-Service + COR
Customer Request/Public Requirement	$24,540	$21,210	$2,243	$23,453
Damage Failure	$12,365	$12,335	$2,047	$14,382
Subtotal Non-Discretionary	$36,905	$33,545	$4,290	$37,835
Asset Condition	$41,120	$38,948	$5,381	$44,329
Non-Infrastructure	$580	$566	$8	$574
System Capacity & Performance	$25,145	$37,435	$2,021	$39,456
Subtotal Discretionary	$66,845	$76,949	$7,410	$84,359
Total	**$103,750**	**$110,494**	**$11,700**	**$122,194**

Attachment 1
FY 2021 Capital Spending by Key Driver Category and Budget Classification
($000)

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 Budget	FY 2020 Forecast	FY 2021 Budget
Customer Requests/Public Requirements	3rd Party Attachments	($910)	$464	$223	$141	$271	$290	$160	$123	$400	$165	$34	$200
	Distributed Generation	$0	$0	($675)	$195	$981	($933)	$3,760	$280	$1,815	$4,675	$5,706	$1,000
	Land and Land Rights	$281	$185	$128	$94	$165	$143	$199	$305	$360	$430	$382	$385
	Meters - Dist	$2,215	$1,497	$1,455	$835	$612	$2,935	$1,844	$2,627	$2,332	$3,030	$3,087	$2,995
	New Business - Commercial	$4,287	$3,391	$3,722	$4,957	$4,781	$7,568	$7,815	$5,625	$7,293	$7,140	$7,471	$8,405
	New Business - Residential	$3,530	$2,833	$2,886	$3,593	$3,769	$5,085	$4,598	$4,618	$4,337	$5,570	$4,540	$4,370
	Outdoor Lighting - Capital	$411	$495	$488	$758	$479	$129	$144	$185	$455	$150	$310	$315
	Public & Regualtory Requirements	$1,539	$1,135	($1,231)	$4,234	$4,214	$770	($124)	$3,078	$2,495	$2,350	$3,603	$2,670
	Transformers & Related Equipment	$3,278	$3,075	$3,415	$2,331	$2,488	$1,425	$1,837	$2,786	$4,503	$3,515	$4,015	$4,200
Customer Requests/Public Requirements Total		**$14,631**	**$13,075**	**$10,410**	**$17,138**	**$17,760**	**$17,412**	**$20,233**	**$19,627**	**$23,989**	**$27,025**	**$29,148**	**$24,540**
Damage/Failure	Damage/Failure	$8,331	$9,574	$7,795	$11,228	$12,284	$11,327	$13,594	$11,426	$10,087	$11,855	$13,648	$10,640
	Major Storms - Dist	$4,863	$3,419	$9,720	$3,146	($9,240)	$3,204	$2,020	$7,758	$3,912	$1,650	$1,815	$1,725
Damage/Failure Total		**$13,194**	**$12,993**	**$17,515**	**$14,374**	**$3,044**	**$14,531**	**$15,614**	**$19,184**	**$13,999**	**$13,505**	**$15,463**	**$12,365**
Asset Condition	Asset Replacement	$5,604	$9,767	$6,984	$14,011	$16,478	$15,957	$12,339	$14,449	$29,984	$29,575	$26,445	$28,140
	Asset Replacement - Southeast Sub	$0	$0	$0	$0	$0	$74	$0	$167	$2,188	$6,250	$6,256	$10,080
	Asset Replacement - South Street	$0	$0	$0	$0	$0	$6,228	$15,070	$24,737		$1,800	$0	
	Asset Replacement - I&M (NE)	$227	$553	$1,086	$6,681	$7,593	$4,811	$3,022	$1,282	$712	$1,700	$1,700	$2,900
	Safety & Other	$0	$0	$0	$213	$1,069	$110	$844	$1,345	$13	$350	$564	$0
Asset Condition Total		**$5,831**	**$10,320**	**$8,070**	**$20,905**	**$25,140**	**$27,179**	**$31,274**	**$41,980**	**$32,897**	**$39,675**	**$34,965**	**$41,120**
Non-Infrastructure	Corporate/Admin/General	$645	$118	$890	($1,245)	$408	($61)	$86	$38	$251	$0	($247)	$0
	General Equipment - Dist	$61	$149	$191	$395	$697	$331	$383	$207	$219	$300	$346	$330
	Telecommunications Capital - Dist	$0	$0	$1,188	$504	$112	$187	$153	$117	$203	$250	$262	$250
Non-Infrastructure Total		**$706**	**$267**	**$2,269**	**($346)**	**$1,217**	**$457**	**$622**	**$362**	**$673**	**$550**	**$361**	**$580**
System Capacity & Performance	Load Relief	$6,012	$8,837	$6,619	$22,762	$20,837	$16,491	$13,800	$21,497	$36,545	$17,690	$20,792	$15,410
	Reliability	$2,799	$2,554	$3,723	$3,210	$5,053	$3,429	$2,571	$4,408	$2,970	$3,355	$4,672	$9,735
	Reliability - Feeder Hardening	$1,984	$2,564	$907	$0	$0	$0	$0	$0		$0	$0	$0
System Capacity & Performance Total		**$10,795**	**$13,955**	**$11,249**	**$25,972**	**$25,890**	**$19,920**	**$16,371**	**$25,905**	**$39,515**	**$21,045**	**$25,464**	**$25,145**
Grand Total		**$45,157**	**$50,610**	**$49,514**	**$78,043**	**$73,051**	**$79,499**	**$84,114**	**$107,058**	**$111,072**	**$101,800**	**$105,401**	**$103,750**

Attachment 2
FY 2021 Project Detail for Capital Spending
($000)

Spending Rationale	Budget Class Codes	Project #	Project Description	FY2021
Customer Request/Public Requirement	**3rd Party Attachments**	COS0022	OCEAN ST-DIST-3RD PARTY ATTCH BLNKT	200
	Distributed Generation	C051909	PS&I DIST GEN RI.	(5,345)
		C080295	TURNING POINT ENERGY N KINGSTOWNRI	400
		C080411	22061267-D-DANPIKE-FOSTER-DANIELSON	250
		C080445	23690335-S-GRNDEV-LINCOLN-GWHWY	190
		C080574	23941071-D-ISM-WARWICK-COWESETT	250
		C080588	24926794-D-EDP-NKNGSTWN-DRYBRDGE	2,000
		C080591	24926794-D-EDP-NKNGSTWN-DRYBRDGE	950
		C081152	25769104-D-HOPKINTON-ASHAWAY-GRAY	420
		C081881	26012283-S-EXETER-EXETER-TENROD	600
		C082402	26127300-D-BLACKHORS-WAREN-TOUISRD	230
		C082679	23459169-D-FREEPT-HOPVALEY-WOODVIL	360
		C082833	26863547-D-PROVWATER-JOHNST-MICHEWY	275
		C082838	25498917-D-QUAHOG-FOSTER-HARTFRDPK	190
		C082906	26678608-D-TURNINPOINT-GREENWCH-HPK	230
	Land and Land Rights	COS0091	LAND AND LAND RIGHTS RI ELECT	385
	Meters - Dist	C083649	RI LANDLINE METER REPLACEMENT	250
		CN04904	NARRAGANSETT METER PURCHASES	1,655
		COS0004	OCEAN ST-DIST-METER BLANKET	1,090
	New Business - Commercial	C046977	RESERVE FOR NEW BUSINESS COMMERCIAL	2,750
		COS0011	OCEAN ST-DIST-NEW BUS-COMM BLANKET.	5,655
	New Business - Residential	C046978	RESERVE FOR NEW BUSINESS RESIDENTIA	250
		COS0010	OCEAN ST-DIST-NEW BUS-RESID BLANKT	4,120
	Outdoor Lighting - Capital	COS0012	OCEAN ST-DIST-ST LIGHT BLANKET.	315
	Public Requirements	C046970	RESERVE FOR PUBLIC REQUIREMENTS UNI	1,540
		C079332	DOTR-CRANSTON: PARK AV BRIDGE480	80
		C080478	DOTR-CUMBERLAND-HOWARD RD BRIDGE	20
		C081434	DOTR-MANVILLE BRIDGENO396 LINC/CUMB	50
		C082090	DOTR-PROV GLENBRIDGE AV BRIDGE REPL	10
		C082316	DOTR-PROV:HAWKINS ST BRIDGE NO. 796	60
		COS0013	OCEAN ST-DIST-PUBLIC REQUIRE BLNKT	910
	Transformers & Related Equipment	CN04920	NARRAGANSETT TRANSFORMER PURCHASES	4,200
Customer Request/Public Requirement Total				**24,540**

Spending Rationale	Budget Class Codes	Project #	Project Description	FY2021
Damage/Failure	**Damage/Failure**	C046986	RESERVE FOR DAMAGE/FAILURE UNIDENTI	150
		C051608	RESERVE FOR DAMAGE/FAILURE SUBSTATI	750
		C081110	WESTERLY T4 FAILURE	100
		C082725	SOCKANOSETT T1 FAILURE	650
		COS0002	OCEAN ST-DIST-SUBS BLANKET.	470
		COS0014	OCEAN ST-DIST-DAMAGE&FAILURE BLNKT	8,520
	Major Storms - Dist	C022433	OSD STORM CAP CONFIRM PROGRAM PROJ	1,725
Damage/Failure Total				**12,365**
Non-Infrastructure	**General Equipment**	COS0006	OCEAN ST-DIST-GENL EQUIP BLANKET	330
	Telecommunications Capital - Dist	C040644	TELECOM SMALL CAPITAL WORK - RI	250
Non-Infrastructure Total				**580**

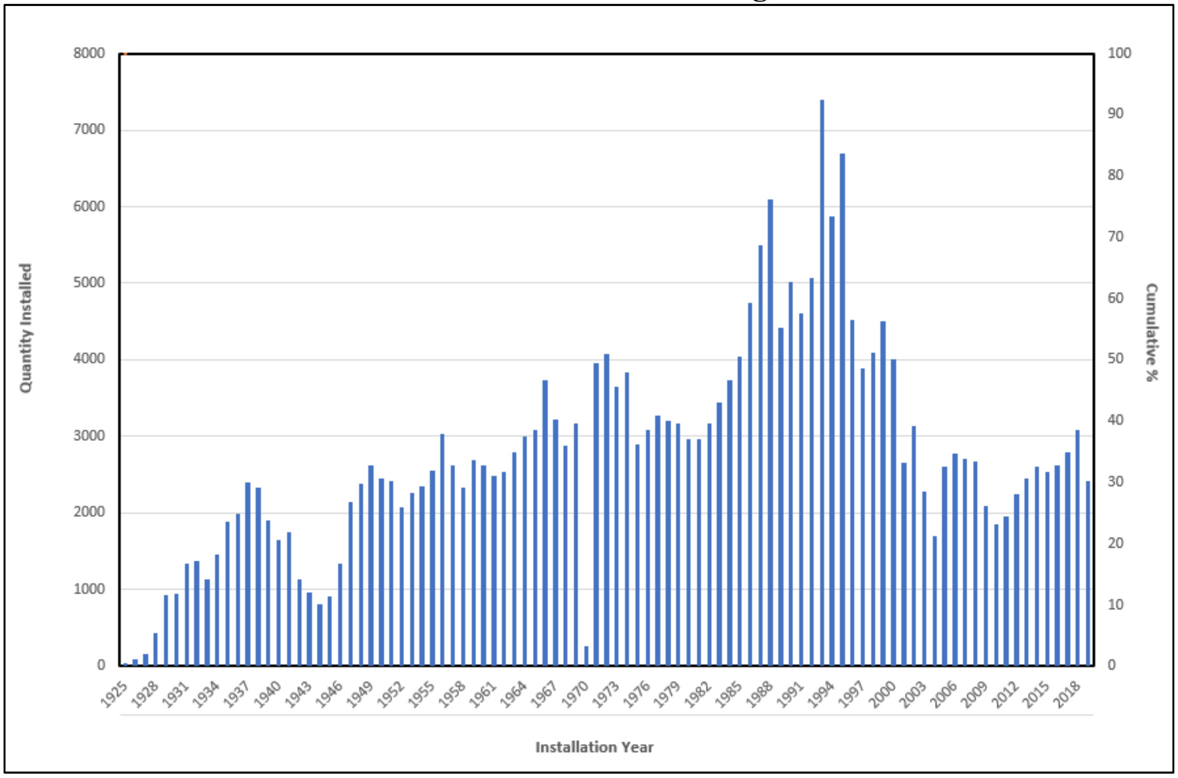
Spending Rationale	Budget Class Codes	Project #	Project Description	FY2021
Asset Condition	**Asset Replacement**	C032019	BATTS/CHARGERS NE SOUTH OS RI	220
		C046697	HOPE SUBSTATION FLOOD RESTORATION	220
		C046982	RESERVE FOR ASSET REPLACEMENT UNIDE	1,000
		C047378	IRURD WILLOWBROOK	360
		C047394	IRURD TANGLEWOOD	40
		C047829	IRURD HIGH HAWK	530
		C049291	IRURD WOOD ESTATES PHASE 2	50
		C049356	IRURD SILVER MAPLE PHASE 2	130
		C050070	IRURD PLACEHOLDER RI	1,080
		C051205	DYER ST REPLACE INDOOR SUBST D-SUB	6,480
		C051211	DYER ST REPLACE INDOOR SUBST D-LINE	680
		C055343	RI UG CABLE PLACEHOLDER	(935)
		C055359	RI UG CABLE REPL PROGRAM - FDR 79F1	340
		C055364	RI UG CABLE REPL PROGRAM - FDR 13F6	255
		C055370	RI UG CABLE REPL PROG FDR 1144/1109	250
		C055371	RI UG CABLE REPL PROG FDR 1142/1105	250
		C055392	RI UG CABLE REPL PROGRAM - SECONDAR	2,135
		C055683	PAWTUCKET NO 1 (D-SUB)	100
		C056947	IRURD JUNIPER HILLS WWARWICK	300
		C057882	IRURD CHATEAU APTS URD REHAB	140
		C057903	IRURD WESTERN HILLS VILLAGE URD-	20
		C057906	IRURD WOODVALE ESTATES URD-	60
		C062633	HMI RI REPLACEMENTS	130
		C069166	PAWTUCKET 1 BREAKER REPLACEMENT	170
		C069506	IRURD NORTH FARM URD	420
		C070207	IRURD EVERGREEN APTS URD E. PROVID	470
		C074307	RI UG 79F1 DUCT CHARLES & ORMS STS	1,020
		C074804	APPONAUG 23KV RETIREMENTS (D-SUB)	210
		C074807	APPONAUG 23KV RETIREMENTS (D-LINE)	140
		C076289	IRURD PEQUAW HONK URD RI-L COMPTON	400

Spending Rationale	Budget Class Codes	Project #	Project Description	FY2021
Asset Condition (cont'd)	**Asset Replacement (cont'd)**	C078474	FRANKLIN SQ SUB_1105 & 1109 NW	370
		C078476	HOPE SUB POLE REPLACEMENT	140
		C078734	PROVSTUDY ADMIRAL ST 4&11KV CONVERT	2,200
		C078796	PROVSTUDY ADMIRAL ST-ROCHAMB D-LINE	150
		C078797	PROVSTUDY ADMIRAL ST-ROCHAMB D-SUB	1,020
		C078800	PROVSTUDY CLARKSON-LIPPIT12KV DLINE	600
		C078802	PROVSTUDY OLNEYVILLE 4KV D-LINE	70
		C078803	PROVSTUDY ADMIRAL ST 12KV MH&DUCT	100
		C078804	PROVSTUDY ADMIRAL ST 12KV CABLES	100
		C078921	RI UG CABLE REPL PROGRAM - FDR 1158	25
		C078926	RI UG CABLE REPL PROGRAM - FDR 1162	230
		C078931	RI UG CABLE REPL PROGRAM - FDR 1166	230
		C081006	FRANKLIN SQ BREAKER REPLACEMENT	1,135
		C081341	CABLE REPLACE WOODLAND MANOR-COVEN	700
		C081716	RI REPL ACNW VAULT VENT BLOWERS	375
		C082439	FRANKLIN SQ-REPLACE 11KV SUB EQUIP	650
		COS0017	OCEAN ST-DIST-ASSET REPLACE BLANKT	3,300
		COS0026	OS-DIST-SUBSTATION ASSET REPL BLNK	180
		C053657	**SOUTHEAST SUBSTATION (D-SUB)**	**3,710**
		C053658	**SOUTHEAST SUBSTATION (D-LINE)**	**6,270**
		C083868	ACNW VAULT 23 REMOVAL	-
	Asset Replacement - I&M (NE)	C026281	I&M - OS D-LINE OH WORK FROM INSP.	2,475
		C080076	I&M - OS SUB-T OH WORK FROM INSP	425
Asset Condition Total				**41,120**

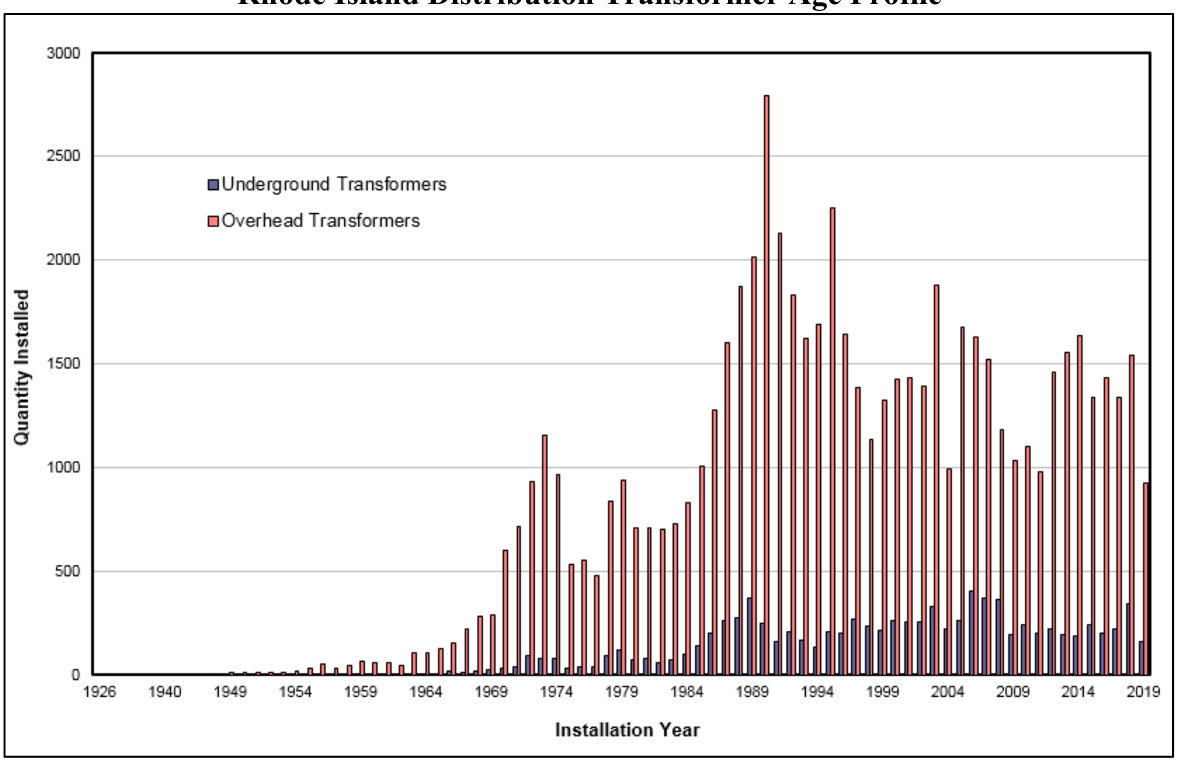
Spending Rationale	Budget Class Codes	Project #	Project Description	FY2021
System Capacity & Performance	**Load Relief**	C005505	IE - OS DIST TRANSFORMER UPGRADES	650
		C013967	PS&I ACTIVITY - RHODE ISLAND	230
		C024159	NEWPORT 69KV LINE 63 (D-LINE)	130
		C028628	NEWPORT SUBTRANS & DIST CONVERSION	5,850
		C046726	EAST PROVIDENCE SUBSTATION (D-SUB)	960
		C046727	EAST PROVIDENCE SUBSTATION (D-LINE)	590
		C052708	VOLT VAR-SUBSTATION	(1,150)
		C054052	NO AQUIDNECK RETIREMENT (D-SUB)	-
		C054054	JEPSON SUBSTATION (D-LINE)	3,685
		C058310	HARRISON SUB IMPROVEMENTS (D-SUB)	200
		C058401	MERTON SUB IMPROVEMENTS (D-SUB)	200
		C058404	KINGSTON SUB IMPROVEMENTS (D-SUB)	210
		C058407	SOUTH AQUIDNECK RETIREMENT (D-SUB)	-
		C065166	WARREN SUB EXPANSION (D-SUB)	230
		C065187	WARREN SUB EXPANSION (D-LINE)	235
		CD00651	BAILEY BROOK RETIREMENT (D-SUB)	-
		CD00652	VERNON RETIREMENT (D-SUB)	-
		CD00656	JEPSON SUBSTATION (D-SUB)	3,210
		COS0016	OCEAN ST-DIST-LOAD RELIEF BLANKET.	180

Spending Rationale	Budget Class Codes	Project #	Project Description	FY2021
System Capacity & Performance (cont'd)	**Reliability**	C059663	CUTOUT MNTED RECLOSER PROGRAM_RI	130
		C065830	RECLOSER REPLACEMENT PROGRAM RI	350
		C074427	EMS EXPANSION - PHILLIPSDALE 20	150
		C074430	EMS EXPANSION - WOOD RIVER 85	200
		C074431	EMS EXPANSION - BONNET 42	100
		C074433	BRISTOL 51 - EMS EXPANSION	430
		C074438	EMS EXPANSION - MERTON 51	100
		C079331	VIPER RECLOSER REPLACEMENT PGM 1-RI	150
		C079494	Peacedale 3V0 D-SUB	125
		C079495	QUONSET 3V0 D-SUB	330
		C079526	RIVERSIDE 3V0 D-SUB	25
		C080894	RI VVO EXP - FARNUM PIKE 123 DIST	750
		C080897	RI VVO EXP - PONTIAC 27 DIST	560
		C080898	RI VVO EXP - FARNUM PIKE 23 DIST	400
		C080901	RI VVO EXP - PONTIAC 27 SUB	575
		C081007	DAVISVILLE 3V0 D-SUB	10
		C081008	WOLF HILL 3V0 D-SUB	20
		C081009	PONTIAC 3V0 D-SUB	30
		C081675	NEW LAFAYETTE 115/12KV (D-SUB)	225
		C081683	NEW LAFAYETTE 115/12KV (D-LINE)	165
		C083317	RI-MH MONITORING PILOT	5
		COS0015	OCEAN ST-DIST-RELIABILITY BLANKET.	1,025
		COS0025	OS-DIST-SUBSTATION LR/REL BLNKT	180
		C079195	Strategic DER Advancement	3,700
System Capacity & Performance Total				**25,145**
Grand Total				**103,750**

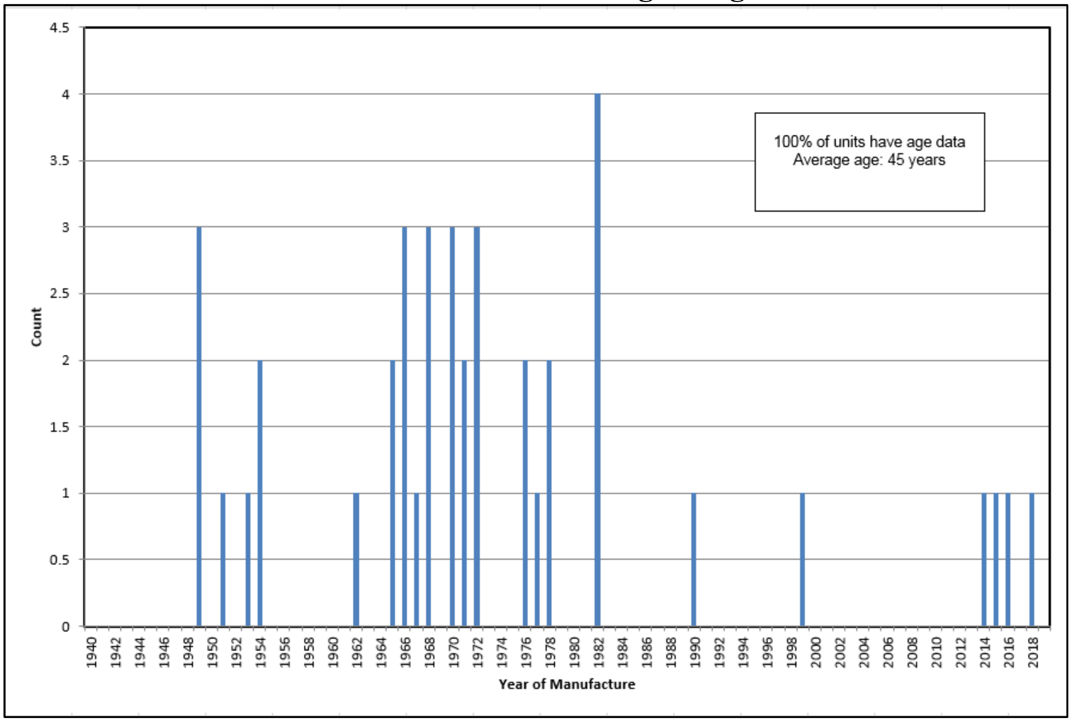
Attachment 3
Rhode Island Distribution Pole Age Profile



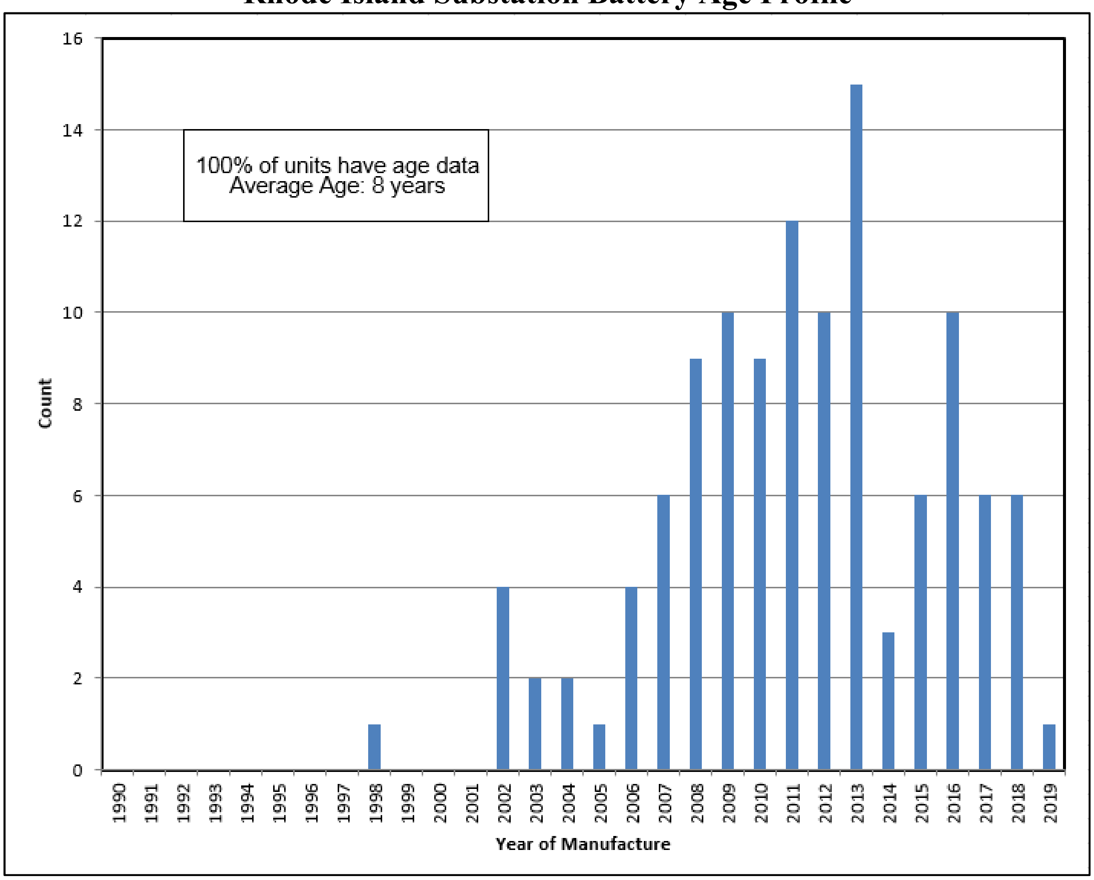
Rhode Island Distribution Transformer Age Profile



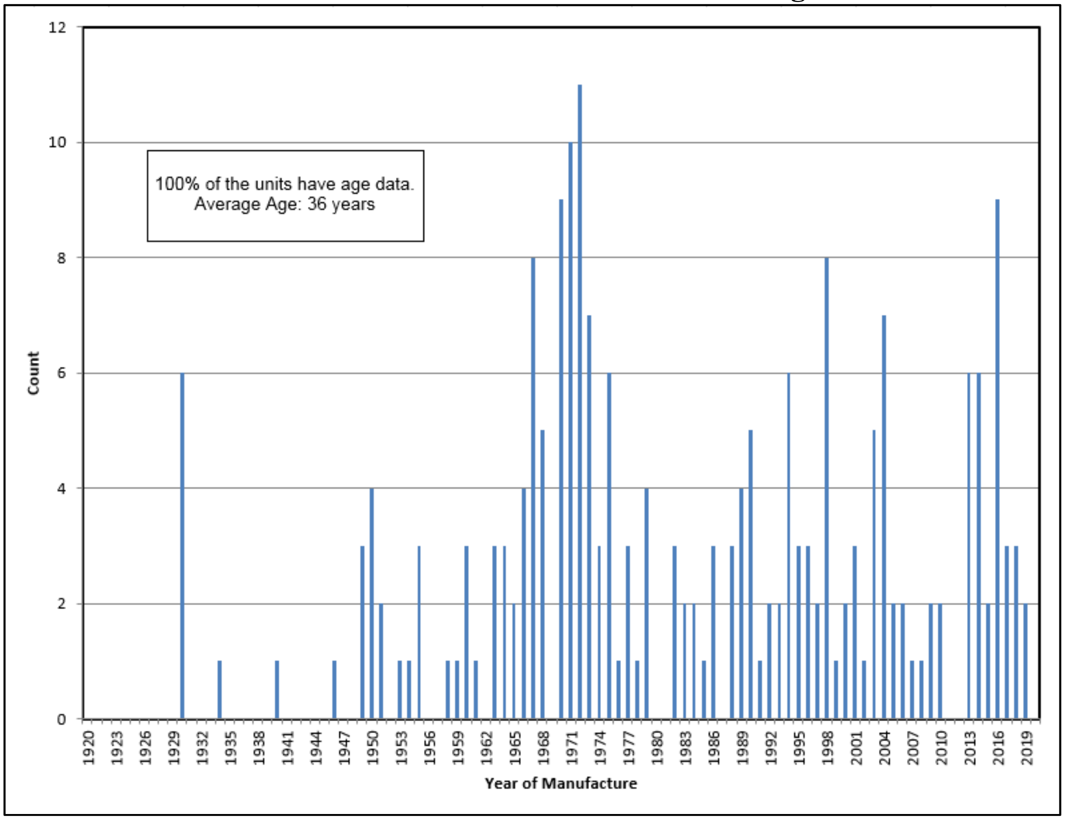
Rhode Island Metalclad Switchgear Age Profile



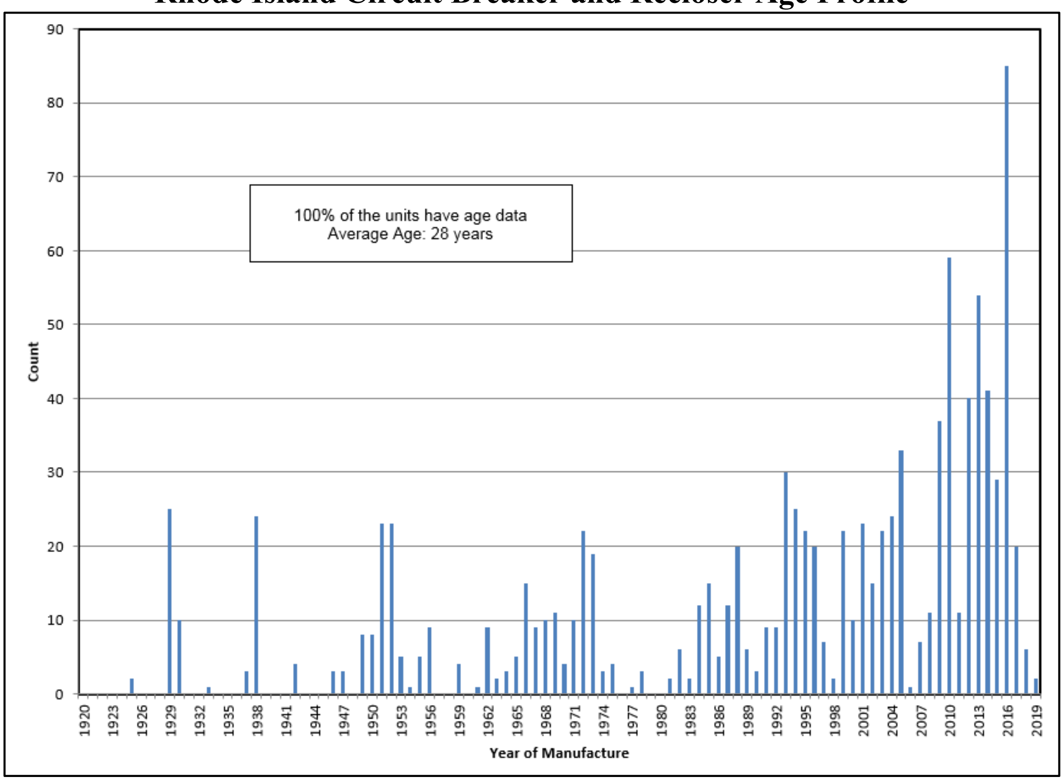
Rhode Island Substation Battery Age Profile



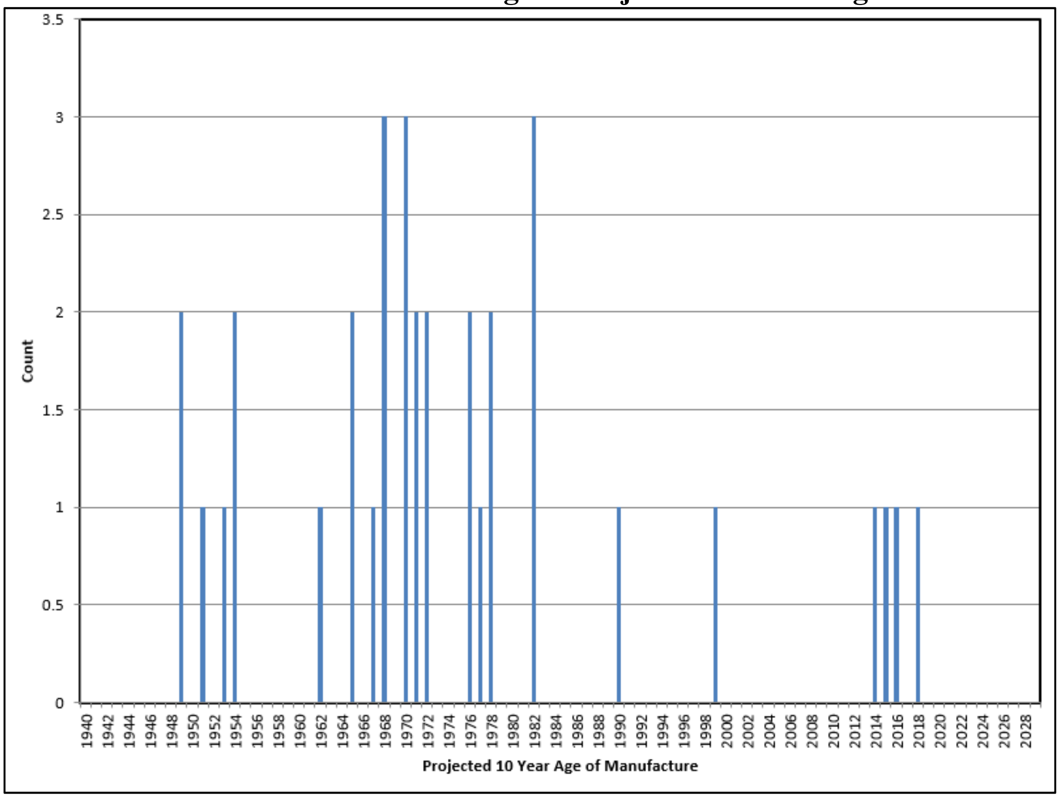
Rhode Island Substation Power Transformer Age Profile



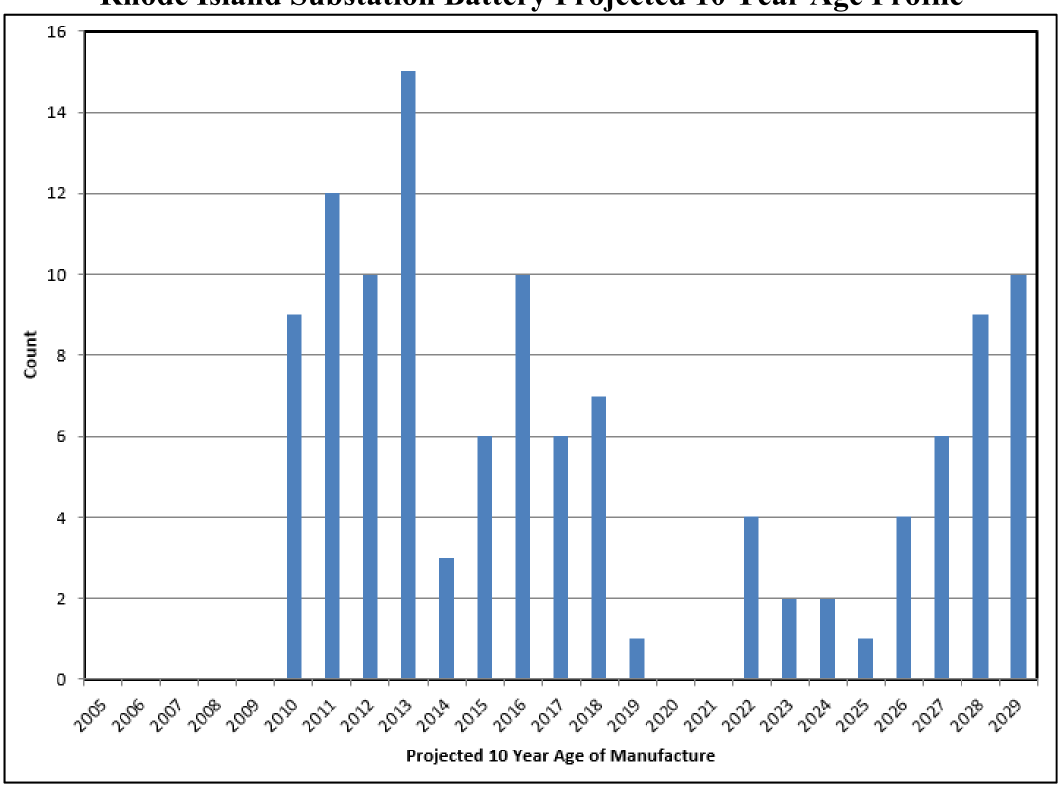
Rhode Island Circuit Breaker and Recloser Age Profile



Rhode Island Metalclad Switchgear Projected 10-Year Age Profile



Rhode Island Substation Battery Projected 10 Year Age Profile



Attachment 4

See also the Excel Version of Attachment 4

	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	FY2020 FYTD Actual Capital Spend (6-MTD)	FY2020 Capital Forecast (6+6 DRAFT)	FY20 ISR Capital Budget	PRELIMINARY FY2021 Capital Budget	ADJUSTMENTS TO PRELIM FY2021 PLAN	ADJUSTED PRELIMARY FY2021 Capital Budget	PRELIMINARY FY2022 Capital Budget	PRELIMINARY FY2023 Capital Budget	PRELIMINARY FY2024 Capital Budget	PRELIMINARY FY2025 Forecast
Discretionary																	
System Capacity & Performance																	
System Capacity & Performance - Major Projects																	
Aquidneck Island	In different phases ranging from engineering through construction : +/-25%	81,125	$ 53,585	Sep-2019	Apr-2017	Sep-2022	36,384	8,592	17,118	14,055	13,485	-	13,485	3,350	-	-	-
East Providence Substation	Early Engineering, Permitting, Procurement : +50%/-25%	16,000	16,000	Feb-2017	Apr-2022	Oct-2024	375	369	488	1,280	4,350	(2,800)	1,550	4,820	5,030	1,375	-
New Lafayette Sub	Project Development				Aug-2021	Feb-2024	-	2	2	-	390	-	390	2,520	1,950	3,025	-
New London Ave Substation #150	Construction : +/- 10%	16,581	2,900	Aug-2018	May-2017	May-2019	15,539	253	514	150	-	-	-	-	-	-	-
Warren Substation	Early Engineering, Permitting, Procurement : +50%/-25%	8,700	8,700	Feb-2017	Mar-2021	Apr-2025	109	131	551	600	865	(400)	465	3,040	2,610	730	170
Quonset Sub	Construction : +/- 10%	9,019	4,520	Aug-2017	May-2016	Sep-2019	7,946	608	673	-	-	-	-	-	-	-	-
Chase Hill (Hopkinton) & Related	Construction : +/- 10%	19,085	2,850	Dec-2015	Aug-2015	Jul-2019	18,681	621	1,011	-	-	-	-	-	-	-	-
Major Projects - Total								10,576	20,357	16,085	19,090	(3,200)	15,890	13,730	9,590	5,130	170
System Capacity & Performance - Other																	
3V0								52	153	210	540	-	540	480	375	-	-
Strategic DER Advancement								-	-	-	5,000	(1,300)	3,700	5,000	5,000	5,000	5,000
Blanket Projects - SCP								692	1,317	1,325	1,385	-	1,385	1,409	1,438	1,467	1,497
EMS/RTU								110	272	310	980	-	980	2,740	720	730	110
Flood Contingency								1	56	-	750	(750)	-	-	-	-	-
OH Line Transformer Replacements								490	518	600	650	-	650	700	710	750	775
Other Load Relief & Reliability								(29)	244	665	365	-	365	100	100	100	100
Recloser Communication								7	7	-	-	-	-	-	-	-	-
Recloser Replacement Program								45	371	850	850	(350)	500	900	950	1,000	1,050
Reserves - SCP								-	-	-	-	-	-	4,295	8,487	10,053	18,906
Storm Hardening								3	3	-	-	-	-	1,100	700	-	-
VVO								378	2,167	1,850	2,285	(1,150)	1,135	-	-	-	-
Other - Total								1,749	5,107	5,810	12,805	(3,550)	9,255	16,724	18,480	19,100	27,438
System Capacity & Performance Total								12,324	25,463	21,895	31,895	(6,750)	25,145	30,454	28,070	24,230	27,608

	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	FY2020 FYTD Actual Capital Spend (6-MTD)	FY2020 Capital Forecast (6+6 DRAFT)	FY20 ISR Capital Budget	PRELIMINARY FY2021 Capital Budget	ADJUSTMENTS TO PRELIM FY2021 PLAN	ADJUSTED PRELIMARY FY2021 Capital Budget	PRELIMINARY FY2022 Capital Budget	PRELIMINARY FY2023 Capital Budget	PRELIMINARY FY2024 Capital Budget	PRELIMINARY FY2025 Forecast
Discretionary																	
Asset Condition																	
Asset Condition - Major Projects																	
Dyer Street - Indoor Sub	Engineering : +50% / -25%	14,154	14,154	Feb-2017	Jun-2020	Dec-2021	1,272	407	1,318	4,900	7,160	-	7,160	1,630	-	-	-
Flood - Hope Substation	Construction : +/- 10%	1,541	1,006	Aug-2018	Oct-2018	May-2020	582	432	877	750	220	-	220	-	-	-	-
Flood - Westerly	Removed from FY2021 Plan	8,000	8,000	May-2015	Aug-2022	Sep-2024	16	-	-	90	-	-	-	-	-	-	-
Providence LT Study	Project Development				Oct-2020	Oct-2029	-	615	1,722	2,860	4,240	-	4,240	11,065	12,485	18,660	11,535
South St Station Rebuild	Construction : +/- 10%	49,450	27,050	Jun-2018	Mar-2016	Dec-2019	51,833	382	966	1,800	-	-	-	-	-	-	-
Flood - Warwick Mall Substation	Construction : +/- 10%	1,678	1,300	Jun-2019	Aug-2018	May-2019	1,248	366	366	-	-	-	-	-	-	-	-
Major Projects - Total								2,201	5,249	10,400	11,620	-	11,620	12,695	12,485	18,660	11,535
Asset Condition - SouthEast Substation																	
New Southeast Sub	Construction : +/- 10%	25,440	18,600	Jul-2019	Oct-2019	Mar-2022	2,560	791	6,331	6,250	10,080	-	10,080	2,095	25	-	-
SouthEast Substation - Total								791	6,331	6,250	10,080	-	10,080	2,095	25	-	-
Asset Condition - Other																	
Asset Replacement - I&M (NE)								1,146	1,700	1,700	4,900	(2,000)	2,900	5,450	6,225	6,525	6,625
Battery Replacement								35	191	300	220	-	220	100	100	100	100
Blanket Projects - AC								2,540	4,419	3,415	3,480	-	3,480	3,554	3,625	3,698	3,772
IRURD								2,124	3,992	4,000	5,000	(1,000)	4,000	5,500	5,750	6,000	6,000
Metalclad Replacement								2,501	4,249	3,300	-	-	-	-	-	-	-
Network Arc Flash								84	564	350	-	-	-	-	-	-	-
Other Asset Condition								2	154	-	-	-	-	-	-	-	-
Other Asset Replacement								1,269	2,136	1,480	1,640	-	1,640	50	-	-	-
Reserves - AR								-	-	-	-	1,000	1,000	6,330	10,200	9,200	13,447
Substation Breakers & Reclosers								473	903	2,425	1,305	-	1,305	830	900	-	-
Substation Transformer Projects								(57)	(57)	80	-	-	-	-	-	-	-
UG Cable Replacements								2,941	4,753	4,750	5,500	(1,000)	4,500	5,750	6,000	6,250	6,500
UG Improvements								200	381	375	375	-	375	-	-	-	-
Other - Total								13,258	23,385	22,175	22,420	(3,000)	19,420	27,564	32,800	31,773	36,444
Asset Condition Total								16,249	34,965	38,825	44,120	(3,000)	41,120	42,354	45,310	50,433	47,979

	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	FY2020 FYTD Actual Capital Spend (6-MTD)	FY2020 Capital Forecast (6+6 DRAFT)	FY20 ISR Capital Budget	PRELIMINARY FY2021 Capital Budget	ADJUSTMENT $ TO PRELIM FY2021 PLAN	ADJUSTED PRELIMARY FY2021 Capital Budget	PRELIMINARY FY2022 Capital Budget	PRELIMINARY FY2023 Capital Budget	PRELIMINARY FY2024 Capital Budget	PRELIMINARY FY2025 Forecast
Discretionary																	
Non-Infrastructure																	
Non-Infrastructure																	
Corporate/Admin/General								(188)	(247)	-	-	-	-	-	-	-	-
General Equipment								190	346	300	330	-	330	332	343	324	330
Telecommunications								134	262	250	250	-	250	260	270	280	290
Non-Infrastructure Total								136	361	550	580	-	580	592	613	604	620
Discretionary Total								28,710	60,789	61,270	76,595	(9,750)	66,845	73,400	73,993	75,267	76,207
Non-Discretionary																	
Customer Request/Public Requirement																	
3rd Party Attachments								(32)	34	165	200	-	200	204	208	212	216
Distributed Generation								2,877	5,704	4,675	1,000	-	1,000	10	10	10	10
Land and Land Rights								168	383	430	385	-	385	395	403	411	419
LNG Plant Service								89	95	-	-	-	-	-	-	-	-
Meters - Dist								2,111	3,087	2,530	2,745	-	2,745	2,813	2,864	2,922	2,980
New Business - Commercial								4,090	7,376	7,140	8,405	-	8,405	8,569	8,784	9,002	9,222
New Business - Residential								1,622	4,540	5,570	4,370	-	4,370	4,464	4,558	4,654	4,751
Outdoor Lighting								264	310	150	315	-	315	323	329	336	343
Public Requirements								1,803	3,603	2,350	2,670	-	2,670	2,428	2,472	2,516	2,560
Transformers & Related Equipment								2,272	4,015	3,515	4,700	(500)	4,200	4,793	4,889	4,987	5,087
Meters - AMR & Landline Projects								-	-	500	250	-	250	275	375	275	-
Customer Request/Public Requirement Total								15,267	29,148	27,025	25,040	(500)	24,540	24,274	24,892	25,325	25,588
Damage/Failure																	
Damage/Failure																	
Damage/Failure								6,950	13,547	11,035	10,740	(1,000)	9,740	10,191	10,395	10,603	10,815
Major Storms (weather)								937	1,815	1,650	1,725	-	1,725	1,750	1,800	1,850	1,900
Reserves - DF								-	101	820	900	-	900	885	920	955	990
Damage/Failure Total								7,887	15,463	13,505	13,365	(1,000)	12,365	12,826	13,115	13,408	13,705
Non-Discretionary Total								23,153	44,611	40,530	38,405	(1,500)	36,905	37,100	38,007	38,733	39,293
Grand Total								51,863	105,401	101,800	115,000	(11,250)	103,750	110,500	112,000	114,000	115,500

Attachment 5

Docket 4600 Analysis
Goals for "New" Electric System – FY2021 New or Incremental Programs and Projects

New Lafayette 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 Lafayette substation project plans to address the reliability and asset condition issues in the South County East area through expansion of the 12.47 kV distribution system and retirement of the 34.5 kV sub-transmission system. The reliability will improve through the retirement of deteriorated assets and improved operational flexibility. Losses will be reduced which may reduce reliance on fossil fuel generation.
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 New Lafayette 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, 3V0 protective equipment. This station will enable the interconnection of more DER interconnections as described above.
Address the challenge of climate change and other forms of pollution	Advances	The New Lafayette station will replace the existing 34.5kV supply with a 115kV supply and enable the Company to expand the existing 12.47 kV distribution system. This will result in greater capacity to interconnect renewable power resources which are needed to meet the state energy policy goals, particularly as those goals relate to reduction of greenhouse gas emissions.
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	Advances	As described above, this project will expand the electric distribution system enabling additional capacity for DER which will enable increased 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. However, the program may facilitate the interconnection of distributed energy resources in a lower cost manner.
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	Advances	This project is aligned with the customer and policy objectives of increased DG interconnections within the RI regulatory framework.

Attachment 5

Strategic DER Advancement (1) Accelerated 3V0

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 Accelerated 3V0 plan is a targeted investment plan which addresses safety and reliability concerns in an efficient manner. It enables cleaner distributed generation sources of energy to readily interconnect to the Company's systems.
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 Accelerated 3V0 plan upgrades associated equipment such as control cable and relays that can optimize the benefits of a modern grid.
Address the challenge of climate change and other forms of pollution	Advances	This plan is considered a system improvement effort that will enable more distributed generation interconnection to the Company's electric system thus addressing the challenges associated with climate change.
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	Advances	The Company's Accelerated 3V0 plan facilitates a customer's investment in their facilities. This plan has a primary benefit in simplifying interconnection schedules and complexities.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	The Company's Accelerated 3V0 plan does not change the compensation distributed energy resources receive. However, the plan may accelerate or simplify access to the electric system such that the distributed energy resources can receive compensation as early as possible.
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 Accelerated 3V0 plan is 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 Accelerated 3V0 plan facilitates the alignment of distribution utility, customer, and policy objectives and interests.

Attachment 5

Strategic DER Advancement (2) Mobile 3V0

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 Mobile 3V0 plan considers purchasing mobile 3V0 units which will expediate the DG interconnection at those stations waiting to be implemented with 3V0 protective equipment. This plan will address safety and reliability concerns in an efficient manner as well as enable cleaner distributed generation sources of energy to readily interconnect to the Company's systems.
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 Mobile 3V0 plan upgrades associated equipment such as control cable and relays that can optimize the benefits of a modern grid.
Address the challenge of climate change and other forms of pollution	Advances	This plan is considered a system improvement effort that will enable more distributed generation interconnection to the Company's electric system thus addressing the challenges associated with climate change.
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	Advances	The Company's Mobile 3V0 plan facilitates a customer's investment in their facilities. This plan has a primary benefit in simplifying interconnection schedules and complexities.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	The Company's Mobile 3V0 plan does not change the compensation distributed energy resources receive. However, the plan may accelerate or simplify access to the electric system such that the distributed energy resources can receive compensation as early as possible.
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 Mobile 3V0 plan is 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 Mobile 3V0 plan facilitates the alignment of distribution utility, customer, and policy objectives and interests.

Attachment 5

Strategic DER Advancement (3) Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors

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 Advanced Capacitor/Regulator Controls and Feeder Monitor Sensors plan is a strategic investment plan which installs advanced controls and functionality on feeders. This plan addresses safety and reliability concerns in an efficient manner.
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	This plan eliminates obsolete equipment and upgrades associated equipment such as capacitors and regulators that can optimize the benefits of a modern grid.
Address the challenge of climate change and other forms of pollution	Advances	This plan is considered an infrastructure improvement effort that will result in a more resilient and hardened system. The improved infrastructure will respond better to challenges associated with climate change such as storms, flooding, etc.
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	Advances or Neutral	This plan does not detract from or facilitate a customer's investment in their facilities. When some interconnection requests are received, system improvements are sometimes required. While not charged to the customer, the interconnection schedule can be impacted.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Neutral	This plan does not change the compensation distributed energy resources receive. However, it may accelerate or simplify access to the electric system such that the distributed energy resources can receive compensation as early as possible.
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	This plan is included in the yearly ISR Plan filing in order to recover the costs of the program 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	Neutral	This plan does not impact alignment of distribution utility, customer, and policy objectives and interests.

Vegetation Management Program

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	National Grid's cycle pruning program seeks to prevent vegetation from growing into the power lines and maintain current reliability levels on all circuits. National Grid's EHTM program improves reliability for customers on selected circuits. National Grid files an annual cost/benefit analysis for both programs.
Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures.	Advances	National Grid's Vegetation Management Program advances modern grid technology. Vegetation must be properly maintained to prevent damage to this technology once it is installed. In some cases, it may be necessary to increase minimum clearances around devices in order for them to operate properly.
Address the challenge of climate change and other forms of pollution.	Advances	By maintaining appropriate clearances between vegetation and power lines, National Grid ensures that its line crews have easy access to make repairs after weather events. Also, removing hazard trees will lessen the damage on those circuits. This will be important as we face more frequent and more intense weather due to climate change.
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.	Advances	Customer investments such as distributed generation, storage, etc. affect the electric power system by creating reverse power flows. The vegetation management program ensures the system is properly maintained.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society.	Neutral	The vegetation management program does not change or impact the compensation distributed energy resources receive.
Appropriately charge customers for the cost they impose on the grid.	Neutral	This goal applies to rate design and tariffs. The vegetation management program does not change the analysis or guidelines that determine the customer costs for their impact to the grid.
Appropriately compensate the distribution utility for the services it provides.	Advances	Spending for the vegetation management program is included in the yearly ISR Plan filing in order to recover the costs of the program.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.	Neutral	The vegetation management program does not impact the alignment of distribution utility, customer, and policy objectives and interests.

Docket 4600 Benefit-Cost Framework

Project Name: New Lafayette Substation
Area Study: South County East

Problem: The South County East area study identified asset condition and loading issues. A condition assessment was performed on the two 34.5 kV supply lines in the area built in the 1930's. Large portions of these lines are installed in rights-of-way (ROW) with limited access or thru backyards with restricted access. The ROW contains wetlands and water crossings. It is challenging for the Company to maintain these lines due to wetland impacts and restrictive backyard construction. A visual inspection of the lines identified significant deterioration on the pole plant and associated equipment. Loading issues were identified for normal and contingency scenarios. Normal loading concerns were identified on several distribution circuits and one substation transformer. The majority of loading concerns were identified for contingency scenarios.

Preferred Plan: The recommended plan is to build a new 115/12.47 kV substation at the existing Lafayette substation site consisting of a single 115/12.47 kV 24/32/40 MVA transformer, (4) regulated feeders, and (1) 7.2 MVAr station capacitor bank. The preferred arrangement of the station is open air, low profile, with a breaker-and-one-half design.

Alternate Plan: The alternate plan is to expand Old Baptist substation by installing a third bay, two additional feeders, and station capacitor banks. This plan would also refurbish the 34.5kV supply to Lafayette substation.

Summary of Benefit - Cost Analysis

Preferred Plan
Benefit Cost Ratio 2.09
Net Benefit/Cost $ 25,893,649.21

Alternate Plan
Benefit Cost Ratio 1.29
Net Benefit/Cost $ 9,020,791.31

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.

New Lafayette Substation Preferred Plan

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	$ (18,608,077.16)	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	$ (5,178,273.64)	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 program/project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition/system performance driven project does not impact water or other fuels.

New Lafayette Substation Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This asset condition/system performance 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	$ 5,080,000.00	Avoided Bulk energy purchases (avoided curtailment). Alternate plan recommends the expansion of Old Baptist 6-circuit 35kV supplied substation. Currently the remaining hosting capacity of the existing three distribution circuits at the station is 2,900 kW. The expansion is expected to increase the available hosting capacity to a range of 3.4 MVA.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This asset condition/system performance driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This asset condition/system performance driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Not Applicable	$ -	This asset condition/system performance driven project does not impact energy costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This asset condition/system performance 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/system performance driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This asset condition/ system performance driven project does not impact transmission costs.

New Lafayette Substation Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
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/ system performance 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/system performance project does not impact DRIPE.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This asset condition/system performance project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Not Applicable	$ -	This asset condition/system performance project does not impact DRIPE.

New Lafayette Substation Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Greenhouse gas compliance costs	Not Applicable	$ -	This asset condition/system improvement 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/system performance project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This asset condition/system performance 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/system performance driven project does not impact Distribution system safety.

New Lafayette Substation Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Distribution system performance	Applicable/Quantifiable	$ 39,100,000.00	There are two 34.5 kV supply lines in the area built in the 1930's (Daivisville 84T3 & Kent County 3312). A condition assessment was performed on these lines with support from local operations and distribution design. Large portions of these lines are installed in rights-of-way (ROW) with limited access or thru backyards with restricted access. The ROW contains wetlands and water crossings. It is challenging for the Company to maintain these lines due to wetland impacts and restrictive backyard construction. A visual inspection of the lines identified significant deterioration on the pole plant and associated equipment. The 3312 supply line experienced multiple outages over a 3 year period, average of 1 outage per year, impacting reliability on the 12kV circuits with a total Customer interruption of 11,811 and Customer minutes interrupted of 983,700. The preferred plan eliminates the aged infrastructure addressing the reliability concerns. Taking no action would leave all the reliability issues unaddressed. Violations of the Distribution Planning Criteria would continue to exist and worsen as time goes by, adversely affecting customer service and reliability performance. Per ICE calculator average cost of outages per year equates to $3.2m. Assuming a average of 1 - 35kV outage a year for the next 20 years results in an avoided cost of an outage including inflation of $39m.
Benefit	Power System	Utility low income	Not Applicable	$ -	This asset condition/system performance driven project does not impact low income participant non-energy benefits.

New Lafayette Substation Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
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.
	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven/system performance project.
	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition/system performance driven project does not impact water or other fuels.
	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This asset condition driven/system performance project does not impact low income participant non-energy benefits.
	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This asset condition driven/system performance project does not directly impact customer empowerment.

New Lafayette Substation Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This asset condition driven/system performance project does not directly impact customer rate and bills.
	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 4,580,000.00	Avoided Bulk energy purchases (avoided curtailment). Lafayette is being expanded and converted to a 4-circuit 115kV supplied substation. Currently the remaining hosting capacity of the existing two distribution circuits station is 1,167 kW. The expansion and supply conversion is expected to increase the available hosting capacity to a range of 30 - 40 MVA.
	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 180,000.00	Avoided Bulk energy purchases (avoided curtailment). Lafayette is being expanded and converted to a 4-circuit 115kV supplied substation. Currently the remaining hosting capacity of the existing two distribution circuits at the station is 1,167 kW. The expansion and supply conversion is expected to increase the available hosting capacity to a range of 30 - 40 MVA.
	Societal	Conservation and community benefits	Not Applicable	$ -	This asset condition/system performance driven project does not directly reduce Environmental Impacts.

New Lafayette Substation Preferred Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This asset condition/system performance driven project does not directly impact economic development.
	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This asset condition/system performance driven project does not impact innovation or market transformation.
	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This asset condition/system performance driven project does not impact low income participant non-energy benefits.
	Societal	Public Health	Applicable/Quantifiable	$ 740,000.00	Avoided Bulk energy purchases (avoided curtailment). Lafayette is being expanded and converted to a 4-circuit 115kV supplied substation. Currently the remaining hosting capacity of the existing two distribution circuits at the station is 1,167 kW. The expansion and supply conversion is expected to increase the available hosting capacity to a range of 30 - 40 MVA.
	Societal	National Security and US international influence	Not Applicable	$ -	This asset condition/system performance driven project does not impact National Security.

New Lafayette Substation Alternate Plan

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	$ (22,350,832.06)	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	$ (8,488,376.62)	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 program/project.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition/system performance driven project does not impact water or other fuels.

New Lafayette Substation Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This asset condition/system performance 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	$ 370,000.00	Avoided Bulk energy purchases (avoided curtailment). Alternate plan recommends the expansion of Old Baptist 6-circuit 35kV supplied substation. Currently the remaining hosting capacity of the existing three distribution circuits at the station is 2,900 kW. The expansion is expected to increase the available hosting capacity to a range of 3.4 MVA.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	This asset condition/system performance driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	This asset condition/system performance driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Not Applicable	$ -	This asset condition/system performance driven project does not impact energy costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	This asset condition/system performance driven program does not impact transmission ancillary services.

New Lafayette Substation Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	This asset condition/system performance driven project does not impact generation capacity or impact REC costs.
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This asset condition/ system performance 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/ system performance 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/system performance project does not impact DRIPE.

New Lafayette Substation Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This asset condition/system performance project is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Not Applicable	$ -	This asset condition/system performance project does not impact DRIPE.
Benefit	Power System	Greenhouse gas compliance costs	Not Applicable	$ -	This asset condition/system improvement 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/system performance project does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This asset condition/system performance 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/system performance driven project does not impact Distribution system safety.

New Lafayette Substation Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Distribution system performance	Applicable/Quantifiable	$ 39,100,000.00	There are two 34.5 kV supply lines in the area built in the 1930's (Davisville 84T3 & Kent County 3312). A condition assessment was performed on these lines with support from local operations and distribution design. Large portions of these lines are installed in rights-of-way (ROW) with limited access or thru backyards with restricted access. The ROW contains wetlands and water crossings. It is challenging for the Company to maintain these lines due to wetland impacts and restrictive backyard construction. A visual inspection of the lines identified significant deterioration on the pole plant and associated equipment. The 3312 supply line experienced multiple outages over a 3 year period, average of 1 outage per year, impacting reliability on the 12kV circuits with a total Customer interruption of 11,811 and Customer minutes interrupted of 983,700. The preferred plan eliminates the aged infrastructure addressing the reliability concerns. Taking no action would leave all the reliability issues unaddressed. Violations of the Distribution Planning Criteria would continue to exist and worsen as time goes by, adversely affecting customer service and reliability performance. Per ICE calculator average cost of outages per year equates to $3.2m. Assuming an average of 1 - 35kV outage a year for the next 20 years results in an avoided cost of an outage including inflation of $39m.
Benefit	Power System	Utility low income	Not Applicable	$ -	This asset condition/system performance driven project does not impact low income participant non-energy benefits.

New Lafayette Substation Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	4. CO_2 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.
	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this asset condition driven/system performance project.
	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This asset condition/system performance driven project does not impact water or other fuels.
	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This asset condition driven/system performance project does not impact low income participant non-energy benefits.
	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This asset condition driven/system performance project does not directly impact customer empowerment.

New Lafayette Substation Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This asset condition driven/system performance project does not directly impact customer rate and bills.
	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 330,000.00	Avoided Bulk energy purchases (avoided curtailment). Alternate plan recommends the expansion of Old Baptist 6-circuit 35kV supplied substation. Currently the remaining hosting capacity of the existing three distribution circuits station is 2,900 kW. The expansion is expected to increase the available hosting capacity to a range of 3.4 MVA.
	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 10,000.00	Avoided Bulk energy purchases (avoided curtailment). Lafayette is being expanded and converted to a 4-circuit 115kV supplied substation. Currently the remaining hosting capacity of the existing two distribution circuits at the station is 1,167 kW. The expansion and supply conversion is expected to increase the available hosting capacity to a range of 30 - 40 MVA.
	Societal	Conservation and community benefits	Not Applicable	$ -	This asset condition/system performance driven project does not directly reduce Environmental Impacts.

New Lafayette Substation Alternate Plan

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Societal	Non-energy costs/benefits: Economic Development	Applicable/Not Quantifiable	$ -	This asset condition/system performance driven project does not directly impact economic development.
	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This asset condition driven/system performance project does not impact innovation or market transformation.
	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This asset condition/system performance project does not impact low income participant non-energy benefits.
	Societal	Public Health	Applicable/Quantifiable	$ 50,000.00	Avoided Bulk energy purchases (avoided curtailment). Lafayette is being expanded and converted to a 4-circuit 115kV supplied substation. Currently the remaining hosting capacity of the existing two distribution circuits at the station is 1,167 kW. The expansion and supply conversion is expected to increase the available hosting capacity to a range of 30 - 40 MVA.
	Societal	National Security and US international influence	Not Applicable	$ -	This asset condition/system performance project does not impact National Security.

Docket 4600 Benefit-Cost Framework

Project Name:	Strategic Distributed Energy Resources Advancement Advanced Capacitor, Regulator, Sensor, and Reclosers
Area Study:	Program

Problem:	With the proliferation of DER comes an increasing complexity in managing core compliance obligations such as system load, voltage, and protection systems that are the key to system safety and reliability. National Grid's Distribution Planning and Asset Management engineers analyze the impact of DER on the electrical distribution power system's performance at the commencement of discrete System Impact Study (SIS) agreements. The analysis conducted identifies potential concerns due to specific DER interconnections and provides system modifications required to maintain compliance. Studies consider all interconnected and proposed DER within the analysis. System modifications are assigned to the project which upsets the balance of any compliance issue. Modifications range from significant infrastructure upgrades to DER project curtailment. As DER 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.
Preferred Plan:	The Company is now putting forth this effort which will proactively install required equipment and controls that are needed to enable the interconnection of DER while allowing the Company to meet its core compliance obligations. These investments are in line with standard actions that the Company currently performs to maintain and address immediate system performance and reliability needs for all customers.
Alternate Plan:	N/A

Summary of Benefit - Cost Analysis

Preferred Plan

Benefit Cost Ratio	1.70
Net Benefit/Cost	$ 8,790,165.64

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 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.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

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	$ (12,625,650.54)	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 program.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This program does not impact water or other fuels.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This program does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 10,366,438.32	This benefit is the value of avoided energy curtailment. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact generation capacity or impact REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact energy costs.
Benefit	Power System	Forward Commitment: Avoided Ancillary Services Value	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact transmission ancillary services.
Benefit	Power System	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact generation capacity or impact REC costs.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This program 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	$ -	While this program enables the interconnection of DER it does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact DRIPE.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This program is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact DRIPE.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Greenhouse gas compliance costs	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact GHG Compliance Costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This program does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This program 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 program does not impact Distribution system safety.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Distribution system performance	Applicable - See Qualification	Applicable - See Qualification	National Grid's existing distribution Electric Power System (EPS) has traditionally been designed and arranged to handle possible loading and voltage situations for one-way power flow. Under such a design, automated equipment and system control has limited use. 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 will be unable to manage loading, voltage, and protection needs. The Company is experiencing DER interconnections on the distribution system that are becoming increasingly complex, stemming from hosting capacity limitations and compliance issues due to heavy saturation (aggregate impact of DER). Ideally these issues are identified during preemptive system impact study analysis, but the aggregation of simple and complex DER has led to the emergence of power quality and voltage issues that cannot be tied back to a specific DER installation. Solutions increasingly draw on the application of advanced capacitors, regulators and reclosers control technologies, and feeder monitoring to maintain compliance obligations. Load, voltage, and protection management are fundamental utility compliance requirements for safe and reliable electric service. The proposed program enables the Company to install the distribution line equipment that will ensure loading levels, voltage levels, and protection systems are sufficient across all times of a year in all areas of the distribution system with various levels of DER penetration. Once integrated with an Automated Distribution Management System (ADMS) the plan allows this fundamental requirement to be achieved in a way that enables greater customer choice and a cleaner economy. It is expected that investments will avoid limitations which are occurring now. The proposed plan is the initial step required to avoid major infrastructure upgrades or DER downsize to allow DER interconnection. In the case of DER curtailment, the advanced capacitors, regulators, and sensors would help limit the necessary times to shut-down and the advanced reclosers would refine and minimize the shutdown switching.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Utility low income	Not Applicable	$ -	This program does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	Applicable - See Qualification	$ -	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.
	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this program.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This program does not impact water or other fuels.
	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This program does not impact low income participant non-energy benefits.
	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This program does not directly impact customer empowerment.
	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This program does not directly impact customer rate and bills.
	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 9,365,492.06	This benefit is the value of avoided energy curtailment. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.
	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 165,492.78	This benefit is the value of avoided energy curtailment. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.

Strategic Distributed Energy Resources Advancement - Advanced Capacitor, Regulator, Sensor, and Reclosers

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Societal	Conservation and community benefits	Not Applicable	$ -	This program does not directly reduce Environmental Impacts.
	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This program does not directly impact economic development.
	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This program does not impact innovation or market transformation.
	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This program does not impact low income participant non-energy benefits.
	Societal	Public Health	Applicable/Quantifiable	$ 1,518,393.02	This benefit is the value of avoided energy curtailment. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.
	Societal	National Security and US international influence	Not Applicable	$ -	This program does not impact National Security.

Docket 4600 Benefit-Cost Framework

Project Name:	Strategic Distributed Energy Resources Advancement Accelerated 3V0 and Mobile 3V0 Procurement
Area Study:	Program

Problem: The addition of distributed energy resources (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. For certain transmission faults, additional transmission protection, zero sequence overvoltage or "3V0" protection, is required to prevent the DER from contributing to fault overvoltage conditions. As DER penetration levels continue to increase, the need for 3V0 is more frequent. In existing stations, this work can be complex, sometimes requiring high voltage yard rearrangement of an extensive duration. Although the cost is a factor, the duration of the 3V0 work can also impact the viability of proposed DER projects. Recent legislation in the state of Rhode Island (RI) with required interconnection timelines also presents execution challenges for the Company. In response to this societal, regulatory, and developer need, National Grid developed a proactive 3V0 program to advance the installation of 3V0 at targeted substations to enable DER interconnections.

Preferred Plan: The Company is now putting forth this effort to accelerate and expand the existing program which has installed 3V0 at 6 of the 12 originally proposed substations since FY2019. The original list, including the remaining substations pending 3V0 installation, was revised into an updated list which now includes the installation of 3V0 at 21 substations over a 5-year program duration. Additionally, to further support DER enablement, National Grid is proposing to purchase mobile 3V0 units which will expedite the installation of 3V0 and DER interconnection at those stations waiting to be implemented with the permanent protective equipment.

Alternate Plan: N/A

Summary of Benefit - Cost Analysis

Preferred Plan

Benefit Cost Ratio	2.23
Net Benefit/Cost	$ 16,491,115.75

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.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

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	$ (13,355,982.01)	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 program.
Cost	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This program does not have non-energy costs that impact water or other fuels.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Cost	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This program does not have societal costs.
Benefit	Power System	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Applicable/Quantifiable	$ 14,316,760.34	This benefit is the value of avoided energy curtailment at the 21 substations included in this program. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.
Benefit	Power System	Renewable Energy Credit Cost / Value	Not Applicable	$ -	While this program enables the interconnection of DER it does not impact generation capacity or impact REC costs.
Benefit	Power System	Retail Supplier Risk Premium	Not Applicable	$ -	While this program enables the interconnection of DER it does not directly impact generation capacity or REC costs.
Benefit	Power System	Forward Commitment: Capacity Value	Not Applicable	$ -	While this program enables the interconnection of DER it does not directly impact energy costs.
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	$ -	While this program enables the interconnection of DER it does not directly impact generation capacity or impact REC costs.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Electric Transmission Capacity Costs / Value	Not Applicable	$ -	This program 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	$ -	While this program enables the interconnection of DER it does not directly provide flexible resources that will impact system operations.
Benefit	Power System	Option value of individual resources	Not Applicable	$ -	While this program enables the interconnection of DER it does not directly impact DRIPE.
Benefit	Power System	Investment under Uncertainty: Real Options Cost / Value	Not Applicable	$ -	This program is not categorized as an investment under uncertainty.
Benefit	Power System	Energy Demand Reduction Induced Price Effect	Not Applicable	$ -	While this program enables the interconnection of DER it does not directly impact DRIPE.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Greenhouse gas compliance costs	Not Applicable	$ -	While this program enables the interconnection of DER it does not directly impact GHG Compliance Costs.
Benefit	Power System	Criteria air pollutant and other environmental compliance costs	Not Applicable	$ -	This program does not impact environmental compliance costs.
Benefit	Power System	Innovation and Learning by Doing	Not Applicable	$ -	This program does not impact innovation or market transformation or provide innovation and learning by doing.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Distribution system safety loss/gain	Applicable - See Qualification	Applicable - See Qualification	In today's evolving electric grid where there is an influx of distributed energy resources located on the customer side, National Grid's distribution systems must work with a variety of non-utility generation sources. The widespread application of renewable energy sources such as photovoltaic and wind technologies have caused a dramatic increase in the use of inverter-based systems. In addition, typical synchronous systems such as small hydro, diesel, methane, and natural gas-powered generator systems are still being installed. Multiple generation sources and the resulting bi-directional power flow bring significant benefits and challenges for the existing and emerging power grids. In particular, the effect of distributed generation on protection concepts and approaches needs to be understood and accounted for. DERs on Delta-Wye (or Ungrounded Wye-Wye) connected transformers cannot contribute zero sequence ground fault current during single line to ground faults on a transmission line, resulting in the voltages on the unfaulted phases rising significantly and rapidly. These overvoltages have the potential to exceed insulation levels of the substation and transmission line equipment, and the maximum continuous operating voltage of surge arresters. In order to detect these overvoltage conditions, ground fault overvoltage, otherwise known as 3V0 protection, on the primary side of the transformer is a standard method employed by National Grid. In the event of a transmission-side overvoltage, this 3V0 protection will open all feeder protective devices in order to disconnect all possible DER sources from the substation bus, thereby stopping the DER from contributing to the transmission-side fault condition. Due to the level and increasing pace of DER adoption, the number of candidate substation increased from the original 12 to the 21 proposed in this paper. This investment also proposes to purchase mobile 3V0 units, which will expedite the installation of 3V0 and DER interconnection at those stations waiting to be implemented with the permanent protective equipment.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Distribution system performance	Applicable - See Qualification	Applicable - See Qualification	In today's evolving electric grid where there is an influx of distributed energy resources located on the customer side, National Grid's distribution systems must work with a variety of non-utility generation sources. The widespread application of renewable energy sources such as photovoltaic and wind technologies have caused a dramatic increase in the use of inverter-based systems. In addition, typical synchronous systems such as small hydro, diesel, methane, and natural gas-powered generator systems are still being installed. Multiple generation sources and the resulting bi-directional power flow bring significant benefits and challenges for the existing and emerging power grids. In particular, the effect of distributed generation on protection concepts and approaches needs to be understood and accounted for. DERs on Delta-Wye (or Ungrounded Wye-Wye) connected transformers cannot contribute zero sequence ground fault current during single line to ground faults on a transmission line, resulting in the voltages on the unfaulted phases rising significantly and rapidly. These overvoltages have the potential to exceed insulation levels of the substation and transmission line equipment, and the maximum continuous operating voltage of surge arresters. In order to detect these overvoltage conditions, ground fault overvoltage, otherwise known as 3V0 protection, on the primary side of the transformer is a standard method employed by National Grid. In the event of a transmission-side overvoltage, this 3V0 protection will open all feeder protective devices in order to disconnect all possible DER sources from the substation bus, thereby stopping the DER from contributing to the transmission-side fault condition. Due to the level and increasing pace of DER adoption, the number of candidate substation increased from the original 12 to the 21 proposed in this paper. This investment proposes an acceleration of the existing program to install 3V0 protective equipment at Rhode Island substations.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
Benefit	Power System	Utility low income	Not Applicable	$ -	This program does not impact low income participant non-energy benefits.
Benefit	Power System	Distribution system and customer reliability / resilience impacts	Applicable - See Qualification	$ -	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.
	Customer	Program participant / prosumer benefits / costs	Not Applicable	$ -	There are no customer or participant actions or investments (CIAC) involved in this program.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Customer	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Not Applicable	$ -	This program does not impact water or other fuels.
	Customer	Low-Income Participant Benefits	Not Applicable	$ -	This program does not impact low income participant non-energy benefits.
	Customer	Consumer Empowerment & Choice	Not Applicable	$ -	This program does not directly impact customer empowerment.
	Customer	Non-participant (equity) rate and bill impacts	Not Applicable	$ -	This program does not directly impact customer rate and bills.
	Societal	Greenhouse gas externality costs	Applicable/Quantifiable	$ 13,215,454.91	This benefit is the value of avoided energy curtailment. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.
	Societal	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$ 228,324.81	This benefit is the value of avoided energy curtailment. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.

Strategic Distributed Energy Resources Advancement - Accelerated 3V0 and Mobile 3V0 Procurement

Benefit/Cost	Level	Mixed Cost-Benefit, Cost, or Benefit Category	Applicable/Not Applicable	NPV (2021)	Qualitative assessment or reason for exclusion:
	Societal	Conservation and community benefits	Not Applicable	$ -	This program does not directly reduce Environmental Impacts.
	Societal	Non-energy costs/benefits: Economic Development	Not Applicable	$ -	This program does not directly impact economic development.
	Societal	Innovation and knowledge spillover (Related to demonstration projects and other RD&D preceding larger scale deployment)	Not Applicable	$ -	This program does not impact innovation or market transformation.
	Societal	Societal Low-Income Impacts	Not Applicable	$ -	This program does not impact low income participant non-energy benefits.
	Societal	Public Health	Applicable/Quantifiable	$ 2,086,557.70	This benefit is the value of avoided energy curtailment. It is expected that investments will avoid limitations to DER projects and interconnection MW size which are occurring now.
	Societal	National Security and US international influence	Not Applicable	$ -	This program does not impact National Security.

Attachment 6
System Reliability Data

A comparison of reliability performance in calendar year (CY) 2018 relative to that of previous years is shown in the charts below. As shown below in Chart 11a, the Company met both its System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance metrics in CY 2018, with SAIFI of 1.001 against a target of 1.05, and SAIDI of 65.11 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days.[10] The Company's performance has shown an improving downward trend over the past several years with major event days excluded.

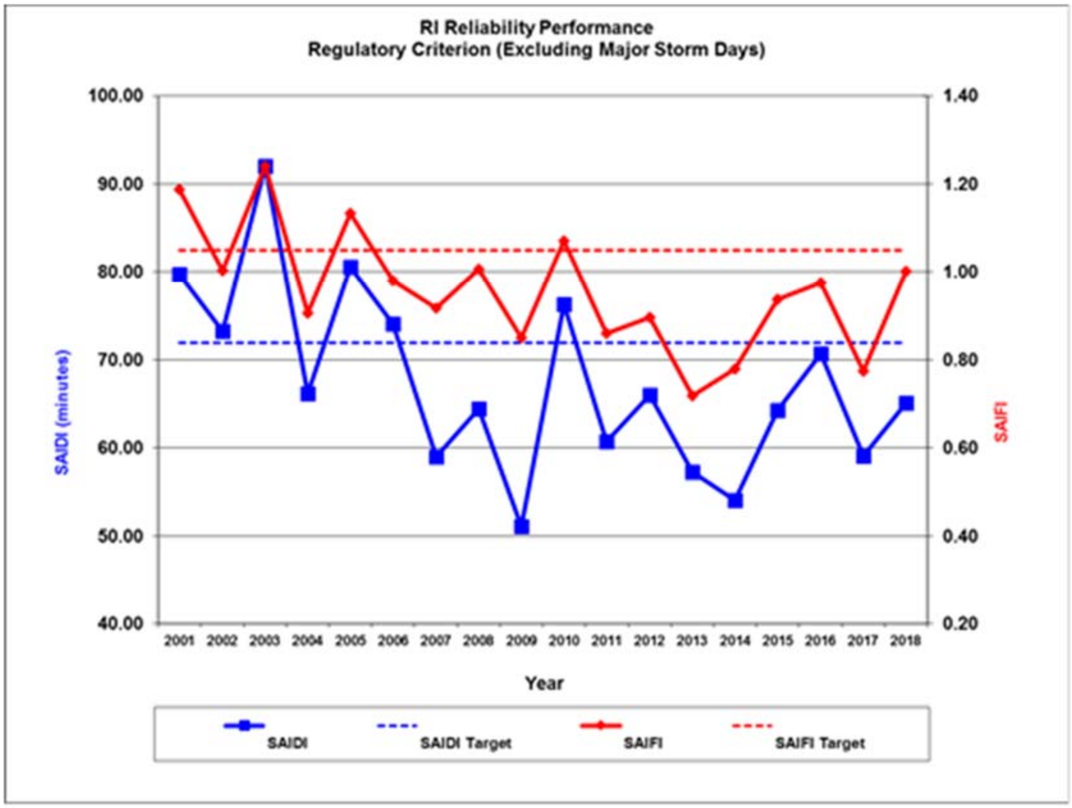
The Plan focuses on the underlying drivers of reliability during the entire year, including major event days would skew that analysis significantly for the small number of days a year that are major event days. For example, including major event days would underestimate the day-to-day drivers of reliability 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 2018, there were 6 days that were characterized as a major event day. The chart below provides additional details including the event, dates, the total number of customers interrupted, and the daily SAIDI performance metric.

[10] A Major Event Day (MED) is defined as a day on which the daily system SAIDI exceeds a MED threshold value (4.49 minutes for CY 2018). 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.

Chart 10
CY 2018 Major Event Days

Event	Days Excluded	Total Customers Interrupted	Daily SAIDI
Winter Storm Riley	3/2/2018	148,051	446.78
Winter Storm Riley	3/3/2018	12,731	10.78
Winter Storm Quinn	03/07/208	12,960	20.15
Winter Storm Quinn	03/08/208	17,531	13.26
Winter Storm Skylar	3/13/2018	59,725	35.93
August Lightning Storm	8/18/2018	27,507	5.74

Chart 11a
RI Reliability Performance CY 2001 – CY 2018
Regulatory Criteria (Excluding Major Event Days)



For informational purposes, Chart 11b below shows reliability performance from CY 2001 to CY 2018, including major event days.

Chart 11b
RI Reliability Performance CY 2001 – CY 2018
Regulatory Criteria (Including Major Event Days)

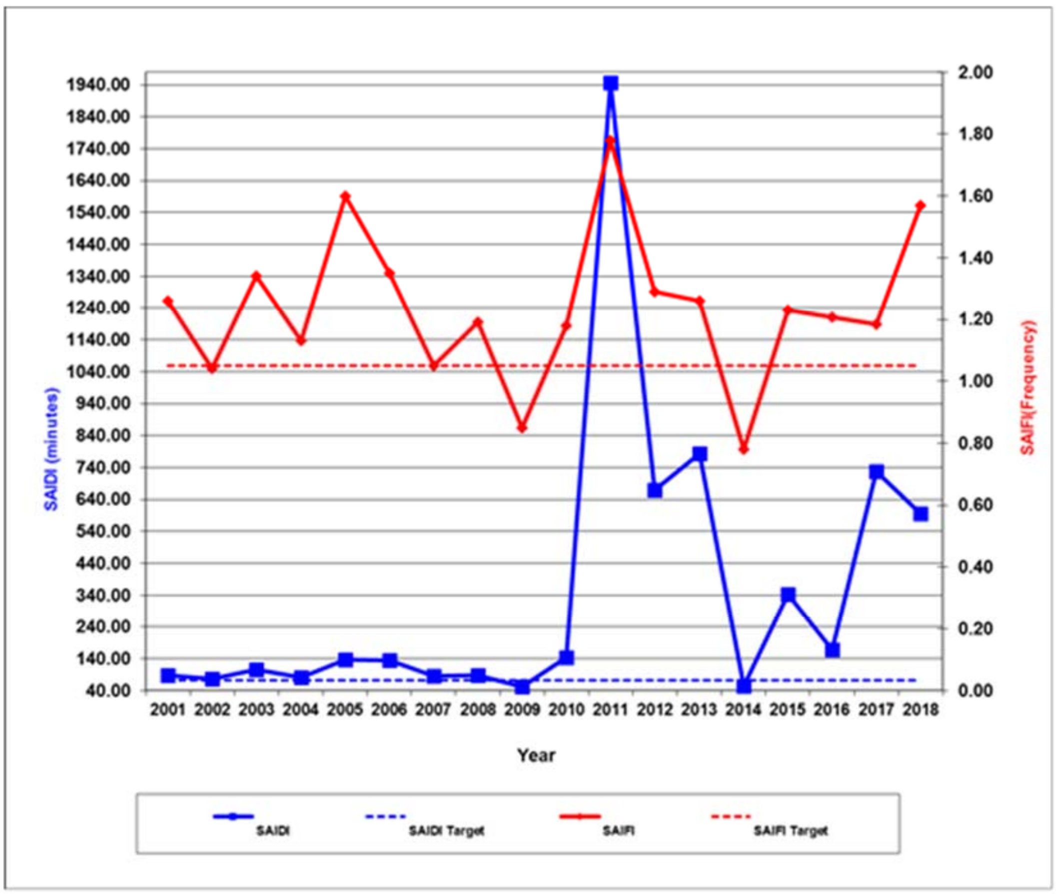


Chart 12a below shows the customers interrupted by cause for CY 2008 through CY 2018.

Chart 12b shows the same information in tabular form.

Chart 12a
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2018)

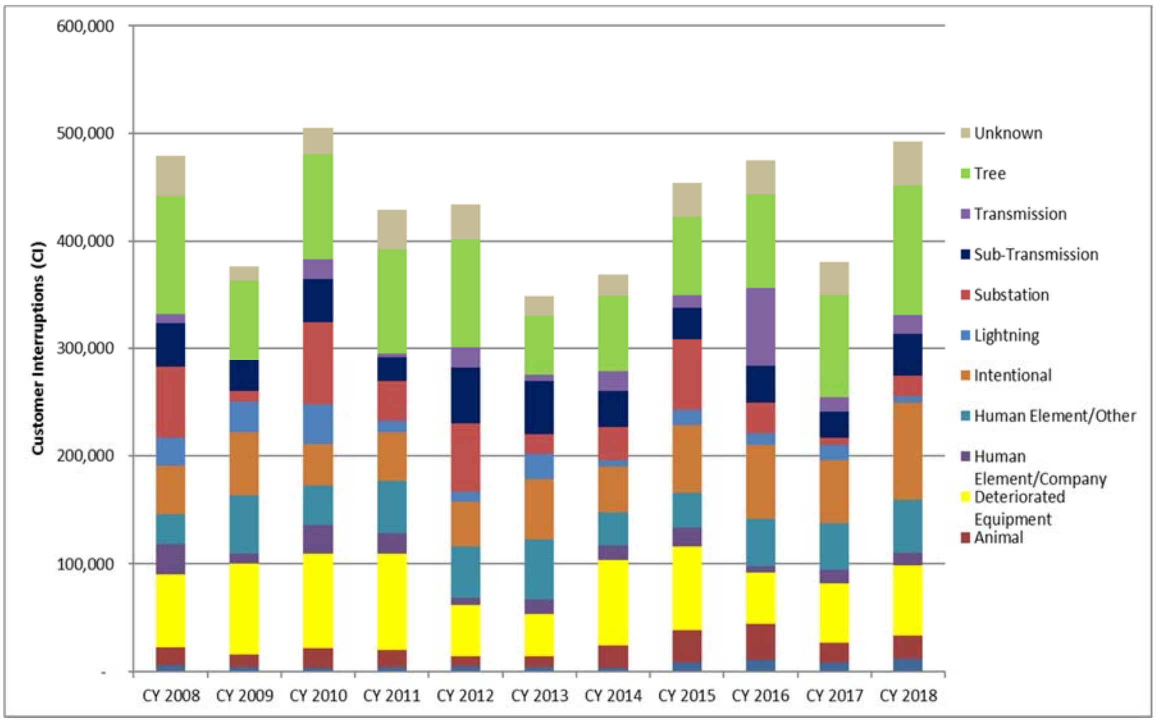


Chart 12b
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Calendar Year (2008-2018)

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

Although service quality for the Company is based on a calendar year, capital spending reported in the Electric ISR Plan is based on the Company's fiscal year (April 1 to March 31). Charts 13a below provides the reliability data as presented in Charts 11 and 12 by fiscal year through FY 2019 (ending March 31, 2019). Chart 13b shows the same information in tabular form.

Chart 13a
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2019)

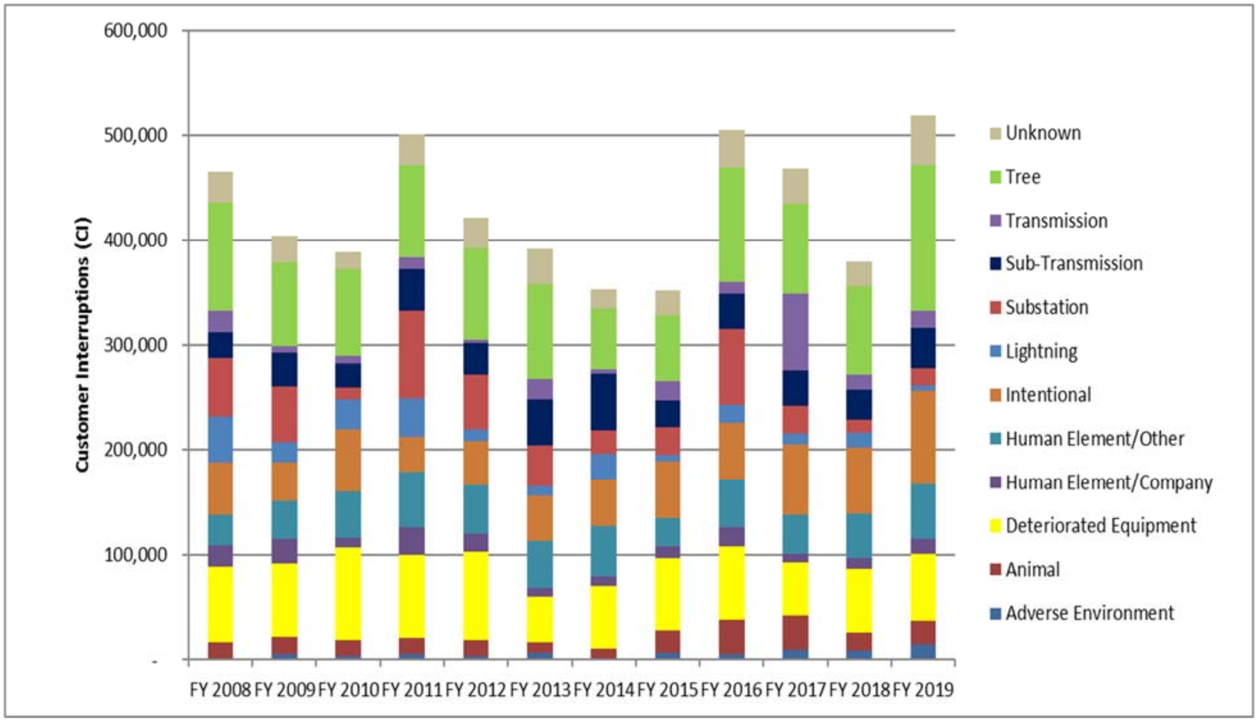


Chart 13b
Rhode Island Customers Interrupted by Cause
Major Event Days Excluded
By Fiscal Year (2008-2019)

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
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
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
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
Human Element/Company	20,633	24,393	8,846	27,305	17,722	8,500	9,304	11,507	17,943	8,266	9,641	14,443
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
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
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
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
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
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
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
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
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

Trees, Human Element/Other, Intentional, and Deteriorated Equipment were the top four drivers affecting customers, accounting for 66 percent of all interruptions in FY 2019. 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.

Section 3
Vegetation Management

Section 3

Vegetation Management Program
FY 2021 Electric ISR Plan

Section 3: FY 2021 Vegetation Management (VM) Program

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, Chart 5, trees were responsible for approximately 139,454 customers interrupted in FY 2019, which represented 27 percent of the total interruptions. Trees were the leading cause of customer interruptions during FY 2019.

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[11].

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 2019 shows, on average, a 15 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 5,016 miles. To maintain a four-year pruning cycle, an average of 1,254 miles, need to be pruned each year. After detailed field analysis of the current circuits due at this time, the FY 2021 plan will require the pruning of 1,222 miles of distribution. The estimated cost for distribution cycle pruning in FY 2021 is $6.1 million.

[11] 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)

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 46 percent of tree-related events and 54 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,[12] a study of the Company's EHTM program was performed. From FY 2008 to FY 2019, the results show an average improvement of tree-related Customers

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12 Electric ISR Plan Vegetation Management Cost Benefit Report, filed September 5, 2012.

Interruptions (CI) by circuit of 68 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 4783, the PUC 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. That summary supports the Company's request that due to the spread of the Gypsy Moth throughout Rhode Island, the Company anticipates continued tree mortality for a few more years. However, the Gypsy Moth infestation is on the decline. In addition to killing large populations of oak trees throughout Rhode Island, the Gypsy Moth infestation has left many other trees weakened, and therefore more susceptible to disease. Finally, Emerald Ash Borer was also discovered in Rhode Island for the first time in 2018. These challenges will 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 a VM budget of $1.8 million in FY 2021.

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 2021 Sub-T VM work is $0.6 million. Currently, the Company has 56 miles of sideline work scheduled for FY 2021.

Police Detail/Flagman – To safely perform the Cycle Pruning and EHTM, the Company is required to hire police details and flagman. For FY 2021, police detail costs are estimated to be $0.8 million. 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, police detail costs represented 5.6 percent of the vegetation management budget in FY 2012, 9.3 percent in FY 2013, 9.0 percent in FY 2014, 8.4 percent in FY 2015, 8.4 percent in FY 2016, 8.2 percent in FY 2017, and 8.2 percent in FY 2018, 8.7 percent in FY 2019, and 7.9 percent in FY 2020. Police and flagging costs are projected to be 7.3 percent for FY 2021.

Importantly, police detail and flagger costs are driven primarily by several 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 several 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 now also 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 several 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.

In FY 2021, the Company projects an additional $0.2 million to focus on pockets of poor performance. These are areas where customers are experiencing a large number of tree-related outages and the Company's routine pruning and hazard tree programs have not proven effective. 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. For FY 2021, the Company expects to spend $1.4 million for the core activities.

Fiscal Year 2021 Vegetation Management Budget

As detailed in Chart 14 below, the FY 2021 Electric ISR Plan proposes to spend approximately $10.6 million for VM in FY 2021. This represents a 2 percent increase from the $10.4 million which was approved for FY 2020.

Chart 14
Vegetation Management Spending
($000)

Category	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021 Proposed Budget
Cycle Prune (Base)	$4,475	$5,414	$5,050	$5,500	$6,150	$5,600	$6,100
Hazard Tree – EHTM	$1,000	$1,000	$950	$1,250	$1,250	$2,250	$1,750
Sub-T (off & on road)	$316	$220	$780	$650	$325	$500	$550
Police/Flagman Detail	$650	$750	$714	$775	$850	$825	$775
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	$1,425
Total	**$7,726**	**$8,884**	**$8,719**	**$9,400**	**$9,800**	**$10,400**	**$10,600**

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.[13]

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.[14]

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

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 2018.

As set forth below, Section 1 provides the Company's results of the FY 2018 Reliability Cost-Benefit for the EHTM and Cycle Pruning Programs. Section 2 provides the results of the Company's Damage Restoration Cost-Benefit for the EHTM Program.

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

Section 1 – FY 2018 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 2018 for the Enhanced Hazard Tree Mitigation (EHTM) Program and FY 2007 through FY 2018 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.

Table 1 below is a summary of the reliability results for the EHTM Program.

Table 1 – EHTM Program Reliability Results

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%	-	-
2018	8,573	5,475	36%	-	-	-	-
Totals	**174,652**	**55,636**	**68%**	**71,958**	**59%**	**58,796**	**66%**

* 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 68% in the first year, 59% in the second year, and 66% 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.

Table 2 below is a summary of the reliability results for the Cycle Pruning Program.

Table 2 – 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%	-	-
2018	26,399	40,527	-54%	-	-	-	-
Totals	447,697	380,465	15%	359,397	20%	390,050	13%

* 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 15% improvement in reliability in the first year, 20% in the second year, and 13% 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 Table 1. In Table 3 below, the % Improvement column on the far right clearly shows that the EHTM Program has provided statistically significant reliability benefits.

Table 3 – 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 (2 year of data post-project)			
EHTM Feeders	8,861	7,112	20%
All RI Feeders (State-wide)	84,265	134,081	-59%
FY 2018 (1 year of data post-project)			
EHTM Feeders	8,573	5,475	36%
All RI Feeders (State-wide)	98,954	170,834	-73%

Section 2 – 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. Table 4 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.

Table 4 - 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%
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	$ 31,084	-121%
49_56_30F1	$ 4,591	$ 3,049	34%
49_56_30F2	$ 12,663	$ 9,859	22%
49_56_46F3	$ 3,339	$ 1,400	58%
49_56_88F1	$ 5,509	$ 6,582	-19%
49_56_33F1	$ 3,037	$ 1,899	37%
49_56_33F2	$ 1,373	$ 2,317	-69%
49_56_33F3	$ 8,298	$ 7,491	10%
49_56_33F4	$ 9,467	$ 7,957	16%
49_56_88F1	$ 6,746	$ 7,051	-5%
49_56_88F5	$ 6,018	$ 7,869	-31%
Totals	**$ 333,215**	**$ 322,458**	**3%**

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. Table 5 below shows the calculation and the benefit as a rolling index over the three years post-project completion.

Table 5 – 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	-	-
2018	$ 935,624	3,098	$ 302	-	-	-	-
Totals	**$ 6,380,521**	**119,015**	**$ 54**	**105,326**	**$ 46**	**101,722**	**$ 41**

In summary, from FY 2008 through FY 2018, the Company spent $6.4 million on the EHTM Program. This resulted in a reduction of 119,015 CI's following the first project year, resulting 105,326 CI's, resulting in a unit cost reduction of $46 per CI. Using three years of data, resulted in a reduction of 101,722 CI's, resulting in a unit cost reduction of $41 per CI.

Using the same method as the EHTM Program, Table 6 below shows the $/ΔCI for the Cycle Pruning Program.

Table 6 – 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	(16,050)	$ (315)	-	-
2018	$ 5,458,000	(14,128)	$ (386)	-	-	-	-
Totals	**$ 47,726,254**	**55,473**	**$ 860**	**43,442**	**$ 973**	**28,070**	**$ 1,326**

In summary, from FY 2009 through FY 2018, the Company spent $47.7 million on cycle pruning. This resulted in a reduction of 55,473 CI's following the first project year, resulting in a unit cost reduction of $860 per CI. Using two years of data, resulted in a reduction of 43,442 CI's, resulting in a unit cost reduction of $973 per CI. Using three years of data, resulted in a reduction of 28,070 CI's, resulting in a unit cost reduction of $1,326 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 Plan and Other O&M
FY 2021 Electric ISR Plan

Section 4: FY 2021 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. 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 four drivers affecting customers, accounting for 12 percent of all interruptions in FY 2019. 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 has agreed with the Division to assess the costs and benefits of the I&M program on an ongoing basis.

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

- The proposed FY 2021 Plan is designed to continue year five of the second five-year inspection cycle and the continuation of repair work for items identified during the initial inspection cycle. The first five-year cycle for all distribution overhead I&M inspections was completed on schedule at the end of FY 2016.
- 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 2021 will test 20 percent of the Designated Contact Voltage Risk Areas (DCVRA's) designated in Docket No. 4237-A.

FY 2021 Inspection and Maintenance and Other O&M Budget

As shown in Chart 16 below, the Company proposes a total I&M program and Other O&M budget of approximately $1.8 million for FY 2021. The largest portion of this is theI&M program, which includes Inspections and Repairs-related costs of $0.6 million. Associated capital costs, which are included in the capital budgets provided 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 $2.9 million, $0.4 million and $0.3 million, respectively. For FY 2021 Other O&M, the Company's proposes to spend $0.4 million to continue the VVO/CVR program. Finally, the Company proposes a budget of $25,000 for continuing the development of the Long Range Plan in FY 2021.

Chart 16
FY 2021 I&M Program and Other O&M Costs
($000)

FY 2021	O&M	Capital	Cost of Removal
Inspections and Repair Related Costs	$600	$2,900	
Opex Related to Capex	$435		
VVO/CVR	$432		
Long Range Plan Study	$25		
Removal Costs			$291
Total	**$1,492**	**$2,900**	**$291**

Section 5
Revenue Requirement

Section 5

Revenue Requirement
FY 2021 Electric ISR Plan

Section 5: Revenue Requirement FY 2021 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, 2021.

As shown on Attachment 1, Page 1, Column (b), the Company's FY 2021 Electric ISR Plan cumulative revenue requirement is $32,302,821 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 2021 Property Tax Recovery Adjustment. Lines 1, 2 and 3 of Column (b) reflect the forecasted FY 2021 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $10,600,000, $1,035,000, and $456,633, respectively, which are described in Section 4 of this document.

The FY 2021 revenue requirement associated with the Company's incremental capital investment in electric utility infrastructure of $20,211,188 is shown on Attachment 1, Page 1, Line 12. This amount includes (1) the $4,440,322 revenue requirement on FY 2021 proposed incremental ISR capital investment, as calculated on Attachment 1, Page 14, (2) the FY 2021 revenue requirements on incremental ISR capital investment for FY 2018 through FY 2020 totaling $10,818,858 and (3) the FY 2021 Property Tax Recovery Adjustment of $4,952,008 from Attachment 1, Page 24. Importantly, the incremental capital investment for the FY 2021 Electric ISR revenue requirement excludes capital investment embedded in base rates in

Docket No. 4770 for FY 2018 through FY 2021. 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 2021 Electric ISR Plan revenue requirement for both O&M expenses and capital investment is $32,302,821 as reflected on Attachment 1, Page 1, Column (b) on Line 13, and is equal to the sum of Lines 4 and 12. Finally, Line 14 reflects the incremental FY 2021 revenue requirement of $14,735,064 above the FY 2020 ISR Plan revenue requirement.

For illustration purposes only, Column (c) of Page 1 provides the FY 2022 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 2021 Electric ISR Plan revenue requirement includes $10,600,000 of VM, $1,035,000 of I&M expenses, and $456,633 of Other Program O&M expenses as shown on Page 1, Lines 1 through 3 in Column (b) of the Attachment.

Electric Infrastructure Investment

<u>Incremental Capital Investment</u>

Page 14 of Attachment 1 to this Section calculates the revenue requirement of incremental capital investment associated with the Company's FY 2021 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 10 of Section 2 in this Plan. The FY 2021 revenue requirement also includes the incremental capital investment associated with the Company's FY 2018 through FY 2020 Electric ISR Plans, excluding investments reflected in rate base in Docket No. 4770 for FY 2018 through FY 2020. Page 18 of Attachment 1 calculates the incremental FY 2018 through FY 2021 ISR capital investment and the related incremental cost of removal, incremental retirements, and incremental net operating loss (NOL) position for the FY 2021 electric ISR revenue requirement. The calculations on Page 18 compare ISR-eligible capital investment, cost of removal, retirements, and net NOL position for FY 2018 through FY 2021 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 2021 revenue requirement for incremental FY 2018, FY 2019, FY 2020, and FY 2021 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 and March 31, 2019 and the estimated ISR plant additions for the Company's fiscal years ended March 31, 2020 and March 31, 2021, 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 2021 is shown on Page 14 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 14 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 2017 through FY 2019 and have been deducted from the total depreciable capital amount as shown on Page 14, 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 PUC in Docket No. 4770, as shown on Line 30, to compute the return and tax portion of the incremental revenue requirement on non-intangible capital investment, as shown on Line 31. As reflected on Line 32, incremental depreciation expense is added to this amount. Line 33, as detailed on Page 16, represents the incremental revenue requirement on intangible capital investment. The sum of these amounts (Line 31, 32 and 33) reflects the annual revenue requirement associated with the incremental capital investment portion of the Company’s Electric ISR Plan on Line 34, which is carried forward to Page 1, Line 8, as part of the total Electric ISR Plan revenue requirement. Similar revenue requirement calculations for the vintage FY 2018, FY 2019, and FY 2020 incremental ISR Plan capital investments are shown on Attachment 1 at Pages 2, 5, and 10. 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 11 to derive the total FY 2021 Electric ISR Plan revenue requirement of $32,302,821 as shown on Page 1, Line 13.

Tax Depreciation Calculation

The tax depreciation calculation for FY 2021 is provided on Attachment 1, Page 15. The tax depreciation amount assumes that a portion of the incremental capital investment, as shown on Line 1 of Page 15, 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 15, Lines 4 through 13 for FY 2021. In 2010, 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

[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 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.

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 that no deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. However, based on current industry practice, the Company has revised its estimate of FY 2019 and FY 2020 bonus depreciation. The Company's FY 2021 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2021 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 PUC, 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 2021 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 14 of Attachment 1, Line 14 and incorporated in the deferred tax calculation. Similar tax depreciation calculations are provided for FY 2018, FY 2019, and FY 2020 on Attachment 1, Pages 3, 6 and 11.

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 2019 tax return in December 2019. 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 2019, FY 2020 and FY 2021 vintage revenue requirement calculations in this docket. If so, the Company will supplement this filing with a revised FY 2021 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 U.S. 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 No. 4770, and the calculation of accumulated deferred income taxes in this filing includes only the incremental amount of forecasted NOL utilization in FY 2021, which is the fiscal year in which the benefit would be reflected in the Company's federal income tax return.

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.

Accumulated Deferred Income Tax Proration Adjustment

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 and FY 2021 proration calculations at Pages 4, 7, 12, and 17, respectively, the effects of which are included in each year's respective revenue requirement.

Property Tax Recovery Adjustment

The Property Tax Recovery Adjustment is shown on Pages 23 and 24 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 2021 revenue requirement includes $4,952,008 for the net property tax recovery adjustment, as shown on Page 1, Line 11.

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 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)
	Operation and Maintenance (O&M) Expenses:			
1	Current Year Vegetation Management (VM)	$10,400,000	$10,600,000	
2	Current Year Inspection & Maintenance (I&M)	$771,000	$1,035,000	
3	Current Year Other Programs	$336,000	$456,633	
4	**Total O&M Expense Component of Revenue Requirement**	**$11,507,000**	**$12,091,633**	**$0**
	Capital Investment:			
5	Actual Revenue Requirement on FY 2018 Incremental Capital included in ISR Rate Base	$2,114,916	$2,057,064	$2,001,528
6	Actual Revenue Requirement on FY 2019 Incremental Capital included in ISR Rate Base	$552,992	$3,562,841	$3,411,969
7	Forecasted Revenue Requirement on FY 2020 Incremental Capital included in ISR Rate Base	$2,197,258	$5,198,953	$5,029,395
8	Forecasted Revenue Requirement on FY 2021 Incremental Capital included in ISR Rate Base		$4,440,322	$8,723,827
9	Subtotal	$4,865,166	$15,259,180	$19,166,719
10	FY 2020 Property Tax Recovery Adjustment	$1,195,591		
11	FY 2021 Property Tax Recovery Adjustment		$4,952,008	
12	**Total Capital Investment Component of Revenue Requirement**	**$6,060,757**	**$20,211,188**	**$19,166,719**
13	**Total Fiscal Year Revenue Requirement**	**$17,567,757**	**$32,302,821**	**$19,166,719**
14	**Incremental Fiscal Year Rate Adjustment**		**$14,735,064**	

Column/Line Notes:

Col (a)	Docket No. 4915, FY 2020 Electric ISR Plan, Revised Section 5: Attachment 1S, Page 1 of 19, Colunm (c)
Col (b) & (c)	
1	Vegetation Management per Section 3, Chart 11
2	Inspection & Maintenance O&M per Section 4, Chart 12
3	Other Program O&M per Section 4, Chart 12
4	Sum of Lines 1 through 3
5	Page 2 of 25, Line 34 column (d) & (e)
6	Page 5 of 25, Line 36, Column (c) & (d)
7	Page 10 of 25, Line 33, Column (b) & (c)
8	Page 14 of 25 Line 34, Column (a) & (b)
9	Sum of Lines 5 through 8
11	Page 24 of 25, Line 62, Column (k) × 1,000
12	Sum of Lines 9 through 11
13	Line 4 + Line 12
14	Line 13 Col (b) - Line 13 Col (a)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Plan
FY 2021 Revenue Requirement on FY 2018 Actual Incremental Capital Investment

Line No.				Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)	Fiscal Year 2022 (e)
	Capital Investment Allowance							
1	*Non-Discretionary Capital*			$3,178,398				
	Discretionary Capital							
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$14,638,256				
3	Total Allowed Capital Included in Rate Base	Page 18 of 25, Line 4(a)		$17,816,654	$0	$0	$0	$0
	Depreciable Net Capital Included in Rate Base							
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$17,816,654	$0	$0	$0	$0
5	Retirements	Page 18 of 25 , Line 10 ,Col (a)		($5,245,072)	$0	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; then = Prior Year Line 6		$23,061,726	$23,061,726	$23,061,726	$23,061,726	$23,061,726
	Change in Net Capital Included in Rate Base							
7	Capital Included in Rate Base	Line 3		$17,816,654	$0	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$17,816,654	$17,816,654	$17,816,654	$17,816,654	$17,816,654
10	Cost of Removal	Page 18 of 25 , Line 7 ,Col (a)		$1,719,991	$1,719,991	$1,719,991	$1,719,991	$1,719,991
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$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%
13	Vintage Year Tax Depreciation:							
14	2018 Spend	Year 1 = Page 3 of 25, Line 23; then = Page 3 of 25, Column (d)		$13,898,861	$571,028	$528,156	$488,605	$451,903
15	Cumulative Tax Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14		$13,898,861	$14,469,889	$14,998,045	$15,486,650	$15,938,553
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; then = Line 6 * Line 12		$392,049	$751,812	$728,751	$728,751	$728,751
17	Cumulative Book Depreciation	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$392,049	$1,143,862	$1,872,612	$2,601,363	$3,330,113
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$13,506,812	$13,326,028	$13,125,433	$12,885,287	$12,608,439
19	Effective Tax Rate		2/	21.00%	21.00%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$2,836,430	$2,798,466	$2,756,341	$2,705,910	$2,647,772
21	Less: FY 2018 Federal NOL	Year 1 = Page 18 of 25 , Line 15 ,Col (a) ; then = Prior Year Line 21		($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)	($2,998,499)
22	Excess Deferred Tax	Year 1= (Line 18 * 31.55% blended FY18 tax rate) - Line 20, Then = Year1		$1,424,969	$1,424,969	$1,424,969	$1,424,969	$1,424,969
23	Net Deferred Tax Reserve before Proration Adjustment	Sum of Lines 20 through 22		$1,262,901	$1,224,936	$1,182,811	$1,132,380	$1,074,242
	Rate Base Calculation:							
24	Cumulative Incremental Capital Included in Rate Base	Line 11		$19,536,645	$19,536,645	$19,536,645	$19,536,645	$19,536,645
25	Accumulated Depreciation	-Line 17		($392,049)	($1,143,862)	($1,872,612)	($2,601,363)	($3,330,113)
26	Deferred Tax Reserve	-Line 23		($1,262,901)	($1,224,936)	($1,182,811)	($1,132,380)	($1,074,242)
27	Year End Rate Base before Deferred Tax Proration	Sum of Lines 24 through 26		$17,881,695	$17,167,848	$16,481,222	$15,802,902	$15,132,290
	Revenue Requirement Calculation:							
28	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 27 ÷ 2; then Average of (Prior + Current Year Line 27)					$16,142,062	$15,467,596
29	Proration Adjustment	Page 4 of 25, 41, (k) and (l)					($2,165)	($2,495)
30	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29					$16,139,898	$15,465,101
31	Pre-Tax ROR	Page 25 of 25, Line 36					8.23%	8.23%
32	Return and Taxes	Line 30 * Line 31					$1,328,314	$1,272,778
33	Book Depreciation	Line 16					$728,751	$728,751
34	**Annual Revenue Requirement**	**Line 32 + Line 33**		**N/A**	**N/A**	**N/A**	**$2,057,064**	**$2,001,528**

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

The Narragansett Electric Company
d/b/a National Grid
FY 2021 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 25, 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 25, 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 2021 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) FY20	(b) FY21	(c) FY22
1	Book Depreciation	Page 2 of 25, Line 16, column (d) & (e)	$729,805	$728,751	$728,751
2	Bonus Depreciation		$0	$0	$0
3	Remaining MACRS Tax Depreciation	Page 3 of 25, Line 7, column, (d)	($528,156)	($488,605)	($451,903)
4	FY18 tax (gain)/loss on retirements		$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	$201,649	$240,145	$276,848
6	Effective Tax Rate		21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	$42,346	$50,431	$58,138
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction				
9	Cost of Removal				
10	Book/Tax Depreciation Timing Difference at 3/31/2017				
11	Cumulative Book / Tax Timer				
12	Effective Tax Rate				
13	Deferred Tax Reserve				
14	Total Deferred Tax Reserve	Line 7 + Line 13	$42,346	$50,431	$58,138
15	Net Operating Loss				
16	Net Deferred Tax Reserve	Line 14 + Line 15	$42,346	$50,431	$58,138
	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	$42,346	$50,431	$58,138

Line No.	Proration Calculation	(h) Number of Days in Month	(i) Proration Percentage	(j) FY20	(k) FY21	(l) FY22
26	April	30	91.78%	$3,240	$3,857	$4,447
27	May	31	83.29%	$2,941	$3,500	$4,035
28	June	30	75.07%	$2,651	$3,155	$3,637
29	July	31	66.58%	$2,353	$2,798	$3,225
30	August	31	58.08%	$2,054	$2,441	$2,814
31	September	30	49.86%	$1,764	$2,096	$2,416
32	October	31	41.37%	$1,466	$1,739	$2,004
33	November	30	33.15%	$1,176	$1,393	$1,606
34	December	31	24.66%	$877	$1,036	$1,195
35	January	31	16.16%	$579	$679	$783
36	February	28	8.49%	$299	$357	$411
37	March	31	0.00%	$0	$0	$0
38	Total	365		$19,399	$23,051	$26,574
39	Deferred Tax Without Proration	Line 25		$42,346	$50,431	$58,138
40	Average Deferred Tax without Proration	Line 25 * 50%		$21,173	$25,215	$29,069
41	Proration Adjustment	Line 38 - Line 40		($1,774)	($2,165)	($2,495)

Column Notes:

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

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

Line No.				Fiscal Year 2019 (a)	Fiscal Year 2020 (b)	Fiscal Year 2021 (c)	Fiscal Year 2022 (d)
	Capital Investment Allowance						
1	*Non-Discretionary Capital*			$7,452,659			
	Discretionary Capital						
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$25,486,776			
3	Total Allowed Capital Included in Rate Base (non-intangible)	Page 18 of 25, Line 4(b)		$32,939,435	$0	$0	$0
	Depreciable Net Capital Included in Rate Base						
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3, Column (a)		$32,939,435	$0	$0	$0
5	Retirements	Page 18 of 25 , Line 10 ,Col (b)		($10,649,479)	$0	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$43,588,914	$43,588,914	$43,588,914	$43,588,914
	Change in Net Capital Included in Rate Base						
7	Capital Included in Rate Base	Line 3, Column (a)		$32,939,435	$0	$0	$0
8	Depreciation Expense			$0	$0	$0	$0
9	Incremental Capital Amount	Year 1 (a) = Line 7 - Line 8; Then = Prior Year Line 9		$32,939,435	$32,939,435	$32,939,435	$32,939,435
10	Cost of Removal	Page 18 of 25 , Line 7 ,Col (b)		$101,073	$101,073	$101,073	$101,073
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$33,040,508**	**$33,040,508**	**$33,040,508**	**$33,040,508**
	Deferred Tax Calculation:						
12	Composite Book Depreciation Rate	As approved per RIPUC Docket No. 4323 and Docket No. 4770	1/	3.26%	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:						
14	2019 Spend	Year 1 = Page 6 of 25, Line 22 Then = Page 6 of 25 Column (d)		$17,240,473	$1,447,020	$1,338,378	$1,238,155
15	Cumulative Tax Depreciation	Year 1 = Line 14; then = Prior Year Line 15 + Current Year Line 14		$17,240,473	$18,687,493	$20,025,871	$21,264,026
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$710,499	$1,377,410	$1,377,410	$1,377,410
17	Cumulative Book Depreciation	Year 1 = Line 16; then = Prior Year Line 17 + Current Year Line 16		$710,499	$2,087,909	$3,465,319	$4,842,728
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$16,529,974	$16,599,584	$16,560,553	$16,421,298
19	Effective Tax Rate			21.00%	21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$3,471,294	$3,485,913	$3,477,716	$3,448,473
21	Add: FY 2019 Federal NOL incremental utilization	Page 18 of 25 , Line 15 ,Col (b)		$8,197,241	$8,197,241	$8,197,241	$8,197,241
22	Net Deferred Tax Reserve before Proration Adjustmen	Sum of Lines 20 through 21		$11,668,535	$11,683,153	$11,674,957	$11,645,713
	Rate Base Calculation:						
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$33,040,508	$33,040,508	$33,040,508	$33,040,508
24	Accumulated Depreciation	-Line 17		($710,499)	($2,087,909)	($3,465,319)	($4,842,728)
25	Deferred Tax Reserve	-Line 22		($11,668,535)	($11,683,153)	($11,674,957)	($11,645,713)
26	Year End Rate Base before Deferred Tax Proration	Sum of Lines 23 through 25		$20,661,474	$19,269,446	$17,900,233	$16,552,066
	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				$18,584,839	$17,226,150
28	Proration Adjustment	Page 7 of 25, Line 41, Column (j) ~ (l)				($188)	($3,400)
29	Average ISR Rate Base after Deferred Tax Proration	Line 27 + Line 28				$18,584,651	$17,222,750
30	Pre-Tax ROR	Page 25 of 25, Line 36				8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30				$1,529,517	$1,417,432
32	Book Depreciation	Line 16				$1,377,410	$1,377,410
33	Annual Revenue Requirement	Line 31 + Line 32				$2,906,926	$2,794,842
34	Revenue Requirement of Plant	Line 33				$2,906,926	$2,794,842
35	Revenue Requirement of Intangible	Page 8 of 25, Line 30, Column (c)~ (l)				$655,914	$617,127
36	**Revenue Requirement**	**Line 34 + Line 35**		**N/A**	**N/A**	**$3,562,841**	**$3,411,969**

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

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement 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 25, Line 3		$32,939,435
2	Capital Repairs Deduction Rate	Per Tax Department	1/	29.08%
3	Capital Repairs Deduction	Line 1 * Line 2		$9,578,788
	Bonus Depreciation			
4	Plant Additions	Line 1		$32,939,435
5	Plant Additions			$0
6	Less Capital Repairs Deduction	Line 3		$9,578,788
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$23,360,647
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$23,360,647
10	Bonus Depreciation Rate	1 * 11.65% * 30%		3.50%
11	Bonus Depreciation Rate	1 * 26.75% * 40%		10.70%
12	Total Bonus Depreciation Rate	Line 10 + Line 11		14.20%
13	Bonus Depreciation	Line 9 * Line 12		$3,316,044
	Remaining Tax Depreciation			
14	Plant Additions	Line 1		$32,939,435
15	Less Capital Repairs Deduction	Line 3		$9,578,788
16	Less Bonus Depreciation	Line 13		$3,316,044
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$20,044,603
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%
19	Remaining Tax Depreciation	Line 17 * Line 18		$751,673
20	FY19 Loss incurred due to retirements	Per Tax Department	2/	$3,492,895
21	Cost of Removal	Page 5 of 25, Line 10		$101,073
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$17,240,473

(b)	(c)	(d)	(e)
20 Year MACRS Depreciation			
MACRS basis:	Line 17	$20,044,603	
		Annual	Cumulative
Fiscal Year			
2019	3.750%	$751,673	$17,240,473
2020	7.219%	$1,447,020	$18,687,493
2021	6.677%	$1,338,378	$20,025,871
2022	6.177%	$1,238,155	$21,264,026
2023	5.713%	$1,145,148	$22,409,174
2024	5.285%	$1,059,357	$23,468,532
2025	4.888%	$979,780	$24,448,312
2026	4.522%	$906,417	$25,354,729
2027	4.462%	$894,390	$26,249,119
2028	4.461%	$894,190	$27,143,309
2029	4.462%	$894,390	$28,037,699
2030	4.461%	$894,190	$28,931,889
2031	4.462%	$894,390	$29,826,279
2032	4.461%	$894,190	$30,720,468
2033	4.462%	$894,390	$31,614,859
2034	4.461%	$894,190	$32,509,048
2035	4.462%	$894,390	$33,403,439
2036	4.461%	$894,190	$34,297,628
2037	4.462%	$894,390	$35,192,018
2038	4.461%	$894,190	$36,086,208
2039	2.231%	$447,195	$36,533,403
	100.00%	$20,044,603	

1/ FY 2019 Electric ISR Plan, Docket 4783, Compliance Section 5: Attachment 1, P3, Line 2
2/ FY 2019 Electric ISR Plan, Docket 4783, Compliance Section 5: Attachment 1, P3, Line 21

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Plan
Calculation of Net Deferred Tax Reserve Proration on FY 2019 Incremental Capital Investment

Line No.	**Deferred Tax Subject to Proration**		(a) FY20	(b) FY21	(c) FY22
1	Book Depreciation	Year 1 = Docket No. 4915; then = Page 5 of 25, Line 16(c)+ Page 8 of 25, Line 19(i)(l), -18(i)(l)	$243,233	$1,871,785	$1,871,785
2	Bonus Depreciation	Col (a) Docket No. 4915; then = Page 6 of 25, Line 13	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Year 1 = Docket No. 4915; then = - Page 6 of 25, Line 6(d)- (Page 8 of 25, Line 16(i)(l), -15(i)(l))	($537,263)	($1,850,897)	($1,494,588)
4	FY 2019 tax (gain)/loss on retirements		$0	$0	$0
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($294,029)	$20,888	$377,197
6	Effective Tax Rate		21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($61,746)	$4,386	$79,211
	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	($61,746)	$4,386	$79,211
15	Net Operating Loss		$0	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($61,746)	$4,386	$79,211
	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	($61,746)	$4,386	$79,211

Line No.	**Proration Calculation**	(h) Number of Days in Month	(i) Proration Percentage	(j) FY20	(k) FY21	(l) FY21
26	April	30	91.78%	($4,723)	$335	$6,058
27	May	31	83.29%	($4,286)	$304	$5,498
28	June	30	75.07%	($3,863)	$274	$4,955
29	July	31	66.58%	($3,426)	$243	$4,395
30	August	31	58.08%	($2,989)	$212	$3,834
31	September	30	49.86%	($2,566)	$182	$3,291
32	October	31	41.37%	($2,129)	$151	$2,731
33	November	30	33.15%	($1,706)	$121	$2,188
34	December	31	24.66%	($1,269)	$90	$1,628
35	January	31	16.16%	($832)	$59	$1,067
36	February	28	8.49%	($437)	$31	$561
37	March	31	0.00%	$0	$0	$0
38	Total	365		($28,223)	$2,005	$36,206
39	Deferred Tax Without Proration	Line 25		($61,746)	$4,386	$79,211
40	Average Deferred Tax without Proration	Line 39 * 50%		($30,873)	$2,193	$39,606
41	Proration Adjustment	Line 38 - Line 40		$2,650	($188)	($3,400)

Column Notes:
(a) Docket no. 4915, Revised section 5: Attachment 1S, Page 4 of 19, column (a)
(i) Sum of remaining days in the year (Col (h)) ÷ 365
(j) through (k) Current Year Line ÷ 12 × Current Month Col (i)

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

Line No.		Reference	Item 1 (a)	Item 2 (b)	FY19 Total (c) = (a) + (b)	Item 1 (d)	Item 2 (e)	FY 20 Total (f) = (d) + (e)	Item 1 (g)	Item 2 (h)	FY 21 Total (i) = (g) + (h)	Item 1 (j)	Item 2 (k)	FY 22 Total (l) = (j) + (k)
	Capital Investment													
1	Start of Rev. Req. Period		09/01/18	09/01/18	09/01/18	04/01/19	04/01/19	04/01/19	04/01/20	04/01/20	04/01/20	04/01/21	04/01/21	04/01/21
2	End of Rev. Req. Period		03/31/19	03/31/19	03/31/19	03/31/20	03/31/20	03/31/20	03/31/21	03/31/21	03/31/21	03/31/22	03/31/22	03/31/22
3	Investment Name	Per Company's Book	Volt-Var Optimization for Lincoln Ope. Center	Volt-Var Optimization IS		Volt-Var Optimization for Lincoln Ope. Center	Volt-Var Optimization IS		Volt-Var Optimization for Lincoln Ope. Center	Volt-Var Optimization IS		Volt-Var Optimization for Lincoln Ope. Center	Volt-Var Optimization IS	
4	Work Order	Per Company's Book	90000194754	90000194755		90000194754	90000194755		90000194754	90000194755		90000194754	90000194755	
5	Total Spend		$2,140,000	$1,320,626	$3,460,626	$2,140,000	$1,320,626	$3,460,626	$2,140,000	$1,320,626	$3,460,626	$2,140,000	$1,320,626	$3,460,626
6	In ServiceDate	Per Company's Book	06/19/18	07/11/18		06/19/18	07/11/18		06/19/18	07/11/18		06/19/18	07/11/18	
7	Book AmortizationPeriod	Per Company's Book	84	84		84	84		84	84		84	84	
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$2,089,048	$1,289,183	$3,378,230	$1,910,714	$1,179,131	$3,089,845	$1,605,000	$990,470	$2,595,470	$1,299,286	$801,809	$2,101,094
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$1,910,714	$1,179,131	$3,089,845	$1,605,000	$990,470	$2,595,470	$1,299,286	$801,809	$2,101,094	$993,571	$613,148	$1,606,719
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$1,999,881	$1,234,157	$3,234,038	$1,757,857	$1,084,800	$2,842,657	$1,452,143	$896,139	$2,348,282	$1,146,429	$707,478	$1,853,907
	Deferred Tax Calculation:													
11	Tax Amortizaton Period	Page 9 of 25	36	36		36	36		36	36		36	36	
12	Tax Expensing	Per Tax Department	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Tax Bonus Rate	Per Tax Department	0%	0%		0%	0%		0%	0%		0%	0%	
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Beginning Acc. Tax Balance	(L. 5 - L. 12- L.14)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%)	$713,262	$440,165	$1,153,427	$713,262	$440,165	$1,153,427	$1,664,492	$1,027,183	$2,691,675	$1,981,426	$1,222,768	$3,204,194
16	Ending Acc. Tax Balance	(L. 5 - L. 12- L.14) × (Y1 × 33.33%; Y2 × 77.78%; Y3 × 92.59%, Y4 × 100%)	$713,262	$440,165	$1,153,427	$1,664,492	$1,027,183	$2,691,675	$1,981,426	$1,222,768	$3,204,194	$2,140,000	$1,320,626	$3,460,626
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$713,262	$440,165	$1,153,427	$1,188,877	$733,674	$1,922,551	$1,822,959	$1,124,975	$2,947,934	$2,060,713	$1,271,697	$3,332,410
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$50,952	$31,443	$82,396	$229,286	$141,496	$370,781	$535,000	$330,157	$865,157	$840,714	$518,817	$1,359,532
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$229,286	$141,496	$370,781	$535,000	$330,157	$865,157	$840,714	$518,817	$1,359,532	$1,146,429	$707,478	$1,853,907
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$140,119	$86,470	$226,589	$382,143	$235,826	$617,969	$687,857	$424,487	$1,112,344	$993,571	$613,148	$1,606,719
21	Average Book / Tax Timer	Line 17 - Line 20	$573,143	$353,695	$926,838	$806,734	$497,848	$1,304,582	$1,135,102	$700,488	$1,835,590	$1,067,142	$658,549	$1,725,691
22	Effective Tax Rate		21%	21%		21%	21%		21%	21%		21%	21%	
23	Deferred Tax Reserve	Line 21 × Line 22	$120,360	$74,276	$194,636	$169,414	$104,548	$273,962	$238,371	$147,103	$385,474	$224,100	$138,295	$362,395
	Rate Base Calculation:													
24	Average Book Balance	Line 10	$1,999,881	$1,234,157	$3,234,038	$1,757,857	$1,084,800	$2,842,657	$1,452,143	$896,139	$2,348,282	$1,146,429	$707,478	$1,853,907
25	Deferred Tax Reserve	Line 23	$120,360	$74,276	$194,636	$169,414	$104,548	$273,962	$238,371	$147,103	$385,474	$224,100	$138,295	$362,395
26	Average Rate Base	Line 24 - Line 25	$1,879,521	$1,159,881	$3,039,402	$1,588,443	$980,252	$2,568,695	$1,213,771	$749,037	$1,962,808	$922,329	$569,183	$1,491,512
	Revenue Requirement Calculation:													
27	Pre-Tax ROR	year 1 = Page 25 of 25, Line 28, column (e)×7÷12 Then = Page 25 of 25, Line 28(e)	4.80%	4.80%		8.23%	8.23%		8.23%	8.23%		8.23%	8.23%	
28	Return and Taxes	Line 26 × Line 27	$90,233	$55,684	$145,917	$130,729	$80,675	$211,404	$99,893	$61,646	$161,539	$75,908	$46,844	$122,751
29	Book Depreciation	Line 9 - Line 8	$178,333	$110,052	$288,386	$305,714	$188,661	$494,375	$305,714	$188,661	$494,375	$305,714	$188,661	$494,375
30	Annual Revenue Requirement	Line 28 + Line 29	$268,566	$165,736	$434,302	$436,443	$269,336	$705,779	$405,608	$250,307	$655,914	$381,622	$235,505	$617,127

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

Line No.				Fiscal Year 2020 (a)	Fiscal Year 2021 (b)	Fiscal Year 2022 (c)
	Capital Investment Allowance					
1	*Non-Discretionary Capital*			$19,983,083	$0	$0
	Discretionary Capital					
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending			$51,629,333	$0	$0
3	Total Allowed Capital Included in Rate Base	Page 18 of 25, Line 4(c)		$71,612,417	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$71,612,417	$0	$0
5	Retirements	Page 18 of 25 , Line 10 ,Col (c)		$19,349,978	$0	$0
6	Net Depreciable Capital Included in Rate Base	Year 1 = Line 4 - Line 5; Then = Prior Year Line 6		$52,262,439	$52,262,439	$52,262,439
	Change in Net Capital Included in Rate Base					
7	Capital Included in Rate Base	Line 3		$71,612,417	$0	$0
8	Depreciation Expense	Page 22 of 25, Line 41, Col (d) ×7 ÷12		$29,112,370	$0	$0
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; then = Prior Year Line 9		$42,500,046	$42,500,046	$42,500,046
10	Cost of Removal	Page 18 of 25 , Line 7 ,Col (c)		$10,562,075	$10,562,075	$10,562,075
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**$53,062,121**	**$53,062,121**	**$53,062,121**
	Deferred Tax Calculation:					
12	Composite Book Depreciation Rate	Page 20 of 25, Line 3, Col (e)	1/	3.16%	3.16%	3.16%
13	Vintage Year Tax Depreciation:					
14	2020 Spend	Year 1 = Page 11 of 25, Line 22, Then = Page 11 of 25, Column (d)		$34,493,158	$3,726,100	$3,446,346
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$34,493,158	$38,219,258	$41,665,603
16	Book Depreciation	Year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$825,747	$1,651,493	$1,651,493
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$825,747	$2,477,240	$4,128,733
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$33,667,411	$35,742,018	$37,536,871
19	Effective Tax Rate			21.00%	21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$7,070,156	$7,505,824	$7,882,743
21	Add: FY 2020 Federal NOL Utilization	Page 18 of 25, Line 15, Col (c)		$1,036,875	$1,036,875	$1,036,875
22	Net Deferred Tax Reserve before Proration Adjustmen	Sum of Lines 20 through 21		$8,107,032	$8,542,699	$8,919,618
	Rate Base Calculation:					
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$53,062,121	$53,062,121	$53,062,121
24	Accumulated Depreciation	-Line 17		($825,747)	($2,477,240)	($4,128,733)
25	Deferred Tax Reserve	-Line 22		($8,107,032)	($8,542,699)	($8,919,618)
26	Year End Rate Base beforee Deferred Tax Proratior	Sum of Lines 23 through 25		$44,129,343	$42,042,182	$40,013,770
	Revenue Requirement Calculation:					
27	Average Rate Base before Deferred Tax Proration Adjustment	Year 1 = Current Year Line 26 * Page 13 of 25, Line 16, Col(e); Then =(Prior Year Line 26 + Current Year Line 26) ÷ 2			$43,085,762	$41,027,976
28	Proration Adjustment	Page 12 of 25, Line 41, Column (k)~(l)			$18,252	$15,791
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29			$43,104,014	$41,043,767
30	Pre-Tax ROR	Page 25 of 25, Line 36			8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30			$3,547,460	$3,377,902
32	Book Depreciation	Line 16			$1,651,493	$1,651,493
33	**Annual Revenue Requirement**	**Line 31 + Line 32**		**N/A**	**$5,198,953**	**$5,029,395**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 20 of 25, 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 25, Line 3		$71,612,417	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	24.67%				
					MACRS			
3	Capital Repairs Deduction	Line 1 * Line 2		$17,666,783	basis:	Line 17	$51,615,183	
							Annual	Cumulative
	Bonus Depreciation				Fiscal Year			
4	Plant Additions	Line 1		$71,612,417	2020	3.750%	$1,935,569	$34,493,158
5	Plant Additions			$0	2021	7.219%	$3,726,100	$38,219,258
6	Less Capital Repairs Deduction	Line 3		$17,666,783	2022	6.677%	$3,446,346	$41,665,603
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$53,945,634	2023	6.177%	$3,188,270	$44,853,873
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		100.00%	2024	5.713%	$2,948,775	$47,802,649
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$53,945,634	2025	5.285%	$2,727,862	$50,530,511
10	Bonus Depreciation Rate (April 2018 - December 2018)	1 * 14.40% * 30%		4.32%	2026	4.888%	$2,522,950	$53,053,461
11	Bonus Depreciation Rate (January 2019 - March 2019)	1 * 85.60% * 0%		0.00%	2027	4.522%	$2,334,039	$55,387,500
12	Total Bonus Depreciation Rate	Line 10 + Line 11		4.32%	2028	4.462%	$2,303,069	$57,690,569
13	Bonus Depreciation	Line 9 * Line 12		$2,330,451	2029	4.461%	$2,302,553	$59,993,122
					2030	4.462%	$2,303,069	$62,296,192
	Remaining Tax Depreciation				2031	4.461%	$2,302,553	$64,598,745
14	Plant Additions	Line 1		$71,612,417	2032	4.462%	$2,303,069	$66,901,815
15	Less Capital Repairs Deduction	Line 3		$17,666,783	2033	4.461%	$2,302,553	$69,204,368
16	Less Bonus Depreciation	Line 13		$2,330,451	2034	4.462%	$2,303,069	$71,507,437
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$51,615,183	2035	4.461%	$2,302,553	$73,809,991
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	2036	4.462%	$2,303,069	$76,113,060
19	Remaining Tax Depreciation	Line 17 * Line 18		$1,935,569	2037	4.461%	$2,302,553	$78,415,613
					2038	4.462%	$2,303,069	$80,718,683
20	FY20 Loss incurred due to retirements	Per Tax Department	2/	$1,998,280	2038	4.461%	$2,302,553	$83,021,236
21	Cost of Removal	Page 10 of 25, Line 10		$10,562,075	2039	2.231%	$1,151,535	$84,172,771
						100.00%	$51,615,183	
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$34,493,158				

1/ Per Tax Department
2/ Per Tax Department

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

Line No.	**Deferred Tax Subject to Proration**		(a) FY20	(b) FY21	(c) FY22
1	Book Depreciation	Page 10 of 25, Line 16	$826,941	$1,651,493	$1,651,493
2	Bonus Depreciation	Page 11 of 25, Line 13	$0	$0	$0
3	Remaining MACRS Tax Depreciation	Page 11 of 25, Line 4, Column (d)	($2,022,961)	($3,726,100)	($3,446,346)
4	FY 2020 tax (gain)/loss on retirements	Page 11 of 25, Line 20	($1,998,280)		
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4	($3,194,300)	($2,074,607)	($1,794,853)
6	Effective Tax Rate		21.00%	21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6	($670,803)	($435,667)	($376,919)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	Page 11 of 25, Line 3	($17,666,783)		
9	Cost of Removal	Page 11 of 25, Line 21	($10,562,075)		
10	Book/Tax Depreciation Timing Difference at 3/31/2020		$0		
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10	($28,228,858)		
12	Effective Tax Rate		21.00%		
13	Deferred Tax Reserve	Line 11 * Line 12	($5,928,060)		
14	Total Deferred Tax Reserve	Line 7 + Line 13	($6,598,863)	($435,667)	($376,919)
15	Net Operating Loss	- Page 10 of 25, Line 21	($1,036,875)	$0	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15	($7,635,738)	($435,667)	($376,919)
	Allocation of FY 2021 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (a) = Line 5	($3,194,300)		
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11	($28,228,858)		
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18	($31,423,157)		
20	Total FY 2020 Federal NOL (Utilization)	- Page 10 of 25, Line 21 / 21%	($4,937,502)		
21	Allocated FY 2020 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20	($4,435,583)		
22	Allocated FY 2020 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20	($501,918)		
23	Effective Tax Rate		21.00%		
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23	($105,403)		
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24	($776,206)	($435,667)	($376,919)

Line No.	**Proration Calculation**	(h) Number of Days in Month	(i) Proration Percentage	(j)	(k)	(l)
26	April	30	91.80%	($23,180)	($33,330)	($28,835)
27	May	31	83.33%	($21,041)	($30,255)	($26,175)
28	June	30	75.14%	($18,972)	($27,279)	($23,600)
29	July	31	66.67%	($16,833)	($24,204)	($20,940)
30	August	31	58.20%	($14,694)	($21,129)	($18,280)
31	September	30	50.00%	($46,426)	($18,153)	($15,705)
32	October	31	41.53%	($38,561)	($15,078)	($13,045)
33	November	30	33.33%	($30,950)	($12,102)	($10,470)
34	December	31	24.86%	($23,086)	($9,027)	($7,810)
35	January	31	16.39%	($15,222)	($5,952)	($5,149)
36	February	29	8.47%	($7,864)	($3,075)	($2,660)
37	March	31	0.00%	$0	$0	$0
38	Total	366		($256,829)	($199,582)	($172,669)
39	Deferred Tax Without Proration	Line 25		($776,206)	($435,667)	($376,919)
40	Average Deferred Tax without Proration	Year 1=Line 39 * Page 13 of 25, Line 16, Col (e); then = Line 39 * 50%		($289,517)	($217,834)	($188,460)
41	Proration Adjustment	Line 38 - Line 40		$32,688	$18,252	$15,791

Column Notes:

(a) Docket no. 4915, Revised section 5: Attachment 1S, Page 4 of 19, column (a)
(i) Sum of remaining days in the year (Col (h)) ÷ 365
(j) Current Year Line 25 * Page 13 of 25, Col (f) * Current Month Col (i)
(k)(l) Current Year, Line 25 ÷ 12 × Current Month Col (i)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Plan
ISR Additions April 2019 through March 2020

Line No.	Month No.	Month	FY 2020 Plant Additions (a)	In Rates (b)	Not In Rates (c) = (a) - (b)	Weight for Days (d)	Weighted Average (e) = (d) * (c)	Weight for Not in Rates (f)=(c)/Total(c)
1								
2	1	Apr-19	8,566,417	6,236,917	2,329,500	0.958	2,232,438	3.25%
3	2	May-19	8,566,417	6,236,917	2,329,500	0.875	2,038,313	3.25%
4	3	Jun-19	8,566,417	6,236,917	2,329,500	0.792	1,844,188	3.25%
5	4	Jul-19	8,566,417	6,236,917	2,329,500	0.708	1,650,063	3.25%
6	5	Aug-19	8,566,417	6,236,917	2,329,500	0.625	1,455,938	3.25%
7	6	Sep-19	8,566,417	-	8,566,417	0.542	4,640,142	11.96%
8	7	Oct-19	8,566,417	-	8,566,417	0.458	3,926,274	11.96%
9	8	Nov-19	8,566,417	-	8,566,417	0.375	3,212,406	11.96%
10	9	Dec-19	8,566,417	-	8,566,417	0.292	2,498,538	11.96%
11	10	Jan-20	8,566,417	-	8,566,417	0.208	1,784,670	11.96%
12	11	Feb-20	8,566,417	-	8,566,417	0.125	1,070,802	11.96%
13	12	Mar-20	8,566,417	-	8,566,417	0.042	356,934	11.96%
14		Total	$102,797,000	$31,184,583	$71,612,417		$26,710,705	100.00%
15	**Total September 2019 through March 2020**				**$ 59,964,917**			
16	**FY2020 Weighted Average Incremental Rate Base Percentage**						**37.30%**	

Column (a)=Page 18 of 25, Line 1(c)
Column(b)=Page 18 of 25, 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 2021 Revenue Requirement on FY 2021 Forcasted Incremental Capital Investment

Line No.				Fiscal Year 2021 (a)	Fiscal Year 2022 (b)
	Capital Investment Allowance				
1	*Non-Discretionary Capital*			$33,545,000	
	Discretionary Capital				
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending (excluding intangibles)			$75,949,000	$0
3	Total Allowed Capital Included in Rate Base (excluding intangibles)	Page 18 of 25, Line 4(d)		$109,494,000	$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
5	Retirements	Page 18 of 25 , Line 10 ,Col (d)		$20,282,977	$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
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		$109,494,000	$0
8	Depreciation Expense	Page 22 of 25, Line 41, Col (d) ×5 ÷12+ Line 62 Column (d) ×7 ÷12		$49,906,920	
9	Incremental Capital Amount	Year 1 = Line 7 - Line 8; Then = Prior Year Line 9		$59,587,080	$59,587,080
10	Cost of Removal	Page 18 of 25 , Line 7 ,Col (d)		$11,494,600	$11,494,600
11	**Total Net Plant in Servic**	**Line 9 + Line 10**		**$71,081,680**	**$71,081,680**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	Page 20 of 25, Line 3, Col (e)	1/	3.16%	3.16%
13	Vintage Year Tax Depreciation:				
14	2020 Spend	Year 1 = Page 15 of 25, Line 22, Column (a), Then = Line Page 15 of 25 , Column (d)		$27,034,837	$7,068,880
15	Cumulative Tax Depreciation	Prior Year Line 15 + Current Year Line 14		$27,034,837	$34,103,717
16	Book Depreciation	year 1 = Line 6 * Line 12 * 50% ; Then = Line 6 * Line 12		$1,409,534	$2,819,068
17	Cumulative Book Depreciation	Prior Year Line 17 + Current Year Line 16		$1,409,534	$4,228,602
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$25,625,303	$29,875,115
19	Effective Tax Rate			21.00%	21.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$5,381,314	$6,273,774
21	Add: FY 2020 Federal (NOL) Utilization	Page 18 of 25, Line 15, Col (d)		($6,764,379)	($6,764,379)
22	Net Deferred Tax Reserve beforee Proration Adjustmen	Sum of Lines 20 through 21		($1,383,066)	($490,605)
	Rate Base Calculation:				
23	Cumulative Incremental Capital Included in Rate Base	Line 11		$71,081,680	$71,081,680
24	Accumulated Depreciation	-Line 17		($1,409,534)	($4,228,602)
25	Deferred Tax Reserve	-Line 22		$1,383,066	$490,605
26	Year End Rate Base before Deferred Tax Proratior	Sum of Lines 23 through 25		$71,055,211	$67,343,682
	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		$35,527,605	$69,199,447
28	Proration Adjustment	Page 17 of 25, Line 41		($6,208)	$41,025
29	Average ISR Rate Base after Deferred Tax Proration	Line 28 + Line 29		$35,521,398	$69,240,472
30	Pre-Tax ROR	Page 25 of 25, Line 36		8.23%	8.23%
31	Return and Taxes	Line 29 * Line 30		$2,923,411	$5,698,491
32	Book Depreciation	Line 16		$1,409,534	$2,819,068
33	Revenue Requirement of Intangible Assets	Page 16 of 25 Line 30 Column (a) ~ (b)		$107,376	$206,267
34	**Annual Revenue Requiremen**	**Line 31 + Line 32 + Line 33**		**$4,440,322**	**$8,723,827**

1/ 3.16% = Composite Book Depreciation Rate for ISR plant per RIPUC Docket No. 4770 (Page 20 of 25, 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 2020 (a)	(b)	(c)	(d)	(e)
	Capital Repairs Deduction							
1	Plant Additions	Page 14 of 25, Line 3		$109,494,000	20 Year MACRS Depreciation			
2	Capital Repairs Deduction Rate	Per Tax Department	1/	10.57%				
					MACRS			
3	Capital Repairs Deduction	Line 1 * Line 2		$11,573,516	basis:	Line 17	$97,920,484	
							Annual	Cumulative
	Bonus Depreciation				Fiscal Year			
4	Plant Additions	Line 1		$109,494,000	2020	3.750%	$3,672,018	$27,034,837
5	Plant Additions			$0	2021	7.219%	$7,068,880	$34,103,717
6	Less Capital Repairs Deduction	Line 3		$11,573,516	2022	6.677%	$6,538,151	$40,641,867
7	Plant Additions Net of Capital Repairs Deduction	Line 4 + Line 5 - Line 6		$97,920,484	2023	6.177%	$6,048,548	$46,690,416
8	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department		0.00%	2024	5.713%	$5,594,197	$52,284,613
9	Plant Eligible for Bonus Depreciation	Line 7 * Line 8		$0	2025	5.285%	$5,175,098	$57,459,711
10	Bonus Depreciation Rate	1 * 75% * 0%		0.00%	2026	4.888%	$4,786,353	$62,246,064
11	Bonus Depreciation Rate	1 * 25% * 0%		0.00%	2027	4.522%	$4,427,964	$66,674,028
12	Total Bonus Depreciation Rate	Line 10 + Line 11		0.00%	2028	4.462%	$4,369,212	$71,043,240
13	Bonus Depreciation	Line 9 * Line 12		$0	2029	4.461%	$4,368,233	$75,411,473
					2030	4.462%	$4,369,212	$79,780,685
	Remaining Tax Depreciation				2031	4.461%	$4,368,233	$84,148,918
14	Plant Additions	Line 1		$109,494,000	2032	4.462%	$4,369,212	$88,518,130
15	Less Capital Repairs Deduction	Line 3		$11,573,516	2033	4.461%	$4,368,233	$92,886,362
16	Less Bonus Depreciation	Line 13		$0	2034	4.462%	$4,369,212	$97,255,574
17	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 14 - Line 15 - Line 16		$97,920,484	2035	4.461%	$4,368,233	$101,623,807
18	20 YR MACRS Tax Depreciation Rates	Per IRS Publication 946		3.750%	2036	4.462%	$4,369,212	$105,993,019
19	Remaining Tax Depreciation	Line 17 * Line 18		$3,672,018	2037	4.461%	$4,368,233	$110,361,252
					2038	4.462%	$4,369,212	$114,730,464
20	FY21 Loss incurred due to retirements	Per Tax Department	2/	$294,703	2038	4.461%	$4,368,233	$119,098,697
21	Cost of Removal	Page 14 of 25, Line 10		$11,494,600	2039	2.231%	$2,184,606	$121,283,303
						100.00%	$97,920,484	
22	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 13, 19, 20, and 21		$27,034,837				

1/ Per Tax Department
2/ Per Tax Department

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

Line No.		Reference	FY 21 (a)	FY 22 (b)
	Capital Investment			
1	Start of Rev. Req. Period		04/01/20	04/01/21
2	End of Rev. Req. Period		03/31/21	03/31/22
3	Investment Name		Volt-Var Optimization IS	Volt-Var Optimization IS
4	Work Order			
5	Total Spend	Section 2, Chart 10, Column 2 note	$1,000,000	$1,000,000
6	In ServiceDate	Estimated in-service date	09/30/20	09/30/20
7	Book AmortizationPeriod	Estimated useful life	84	84
8	Beginning Book Balance	Line 5 ÷ Line 7 × month to Year End, 2019,2020, 2021	$0	$928,571
9	Ending Book Balance	Line 5 ÷ Line 7 × month to Year End, 2020 ,2021, 2022	$928,571	$785,714
10	Average Book Balance	(Line 8 + Line 9) ÷ 2	$464,286	$857,143
	Deferred Tax Calculation:			
11	Tax Amortizaton Period	Page 9 of 25	36	36
12	Tax Expensing	Per Tax Department	$0	$0
13	Tax Bonus Rate	Per Tax Department	0%	0%
14	Bonus Depreciation	Year 1 = (L. 5 - L. 12) × L.13, Then = 0	$0	$0
15	Beginning Acc. Tax Balance	(L. 5 - L. 12- L.14)× (Y1 ×0; Y2 × 33.33%; Y3 × 72.78%; Y4 × 92.59%, Y5 × 100%)	$0	$333,300
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
17	Average Acc. Tax Balance	(Line 15 + Line 16) ÷ 2	$166,650	$555,550
18	Beginning Acc. Dep. Balance	Line 5 - Line 8	$0	$71,429
19	Ending Acc. Dep. Balance	Line 5 - Line 9	$71,429	$214,286
20	Average Acc. Dep. Balance	(Line 18 + Line 19) ÷ 2	$35,714	$142,857
21	Average Book / Tax Timer	Line 17 - Line 20	$130,936	$412,693
22	Effective Tax Rate		21%	21%
23	Deferred Tax Reserve	Line 21 × Line 22	$27,497	$86,666
	Rate Base Calculation:			
24	Average Book Balance	Line 10	$464,286	$857,143
25	Deferred Tax Reserve	Line 23	$27,497	$86,666
26	Average Rate Base	Line 24 - Line 25	$436,789	$770,477
	Revenue Requirement Calculation:			
27	Pre-Tax ROR	year 1 = Page 25 of 25, Line 28, column (e)×7÷12 Then = Page 25 of 25, Line 28(e)	8.23%	8.23%
28	Return and Taxes	Line 26 × Line 27	$35,948	$63,410
29	Book Depreciation	Line 9 - Line 8	$71,429	$142,857
30	Annual Revenue Requirement	Line 28 + Line 29	$107,376	$206,267

The Narragansett Electric Company
d/b/a National Grid
FY 2021 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) FY21	(b) FY22
1	Book Depreciation	Page 14 of 25, Line 16 + (Page 16 of 25, Line 19- Line 18)		$1,480,963	$2,961,925
2	Bonus Depreciation	Page 15 of 25, Line 13		$0	$0
3	Remaining MACRS Tax Depreciation	- Page 15 of 25, column (d) - (Page 16 of 25, Line 16- Line 15)		($4,005,318)	($7,513,380)
4	FY 2021 tax (gain)/loss on retirements	- Page 15 of 25, Line 20		($294,703)	
5	Cumulative Book / Tax Timer	Sum of Lines 1 through 4		($2,819,058)	($4,551,454)
6	Effective Tax Rate			21.00%	21.00%
7	Deferred Tax Reserve	Line 5 * Line 6		($592,002)	($955,805)
	Deferred Tax Not Subject to Proration				
8	Capital Repairs Deduction	- Page 15 of 25, Line 3		($11,573,516)	
9	Cost of Removal	- Page 15 of 25, Line 21		($11,494,600)	
10	Book/Tax Depreciation Timing Difference at 3/31/2021			$0	
11	Cumulative Book / Tax Timer	Line 8 + Line 9 + Line 10		($23,068,116)	
12	Effective Tax Rate			21.00%	
13	Deferred Tax Reserve	Line 11 * Line 12		($4,844,304)	
14	Total Deferred Tax Reserve	Line 7 + Line 13		($5,436,307)	($955,805)
15	Net Operating Loss	- Page 14 of 25, Line 21		$6,764,379	$0
16	Net Deferred Tax Reserve	Line 14 + Line 15		$1,328,073	($955,805)
	Allocation of FY 2020 Estimated Federal NOL				
17	Cumulative Book/Tax Timer Subject to Proration	Col (b) = Line 5		($2,819,058)	
18	Cumulative Book/Tax Timer Not Subject to Proration	Line 11		($23,068,116)	
19	Total Cumulative Book/Tax Timer	Line 17 + Line 18		($25,887,174)	
20	Total FY 2021 Federal NOL (Utilization)	- Page 14 of 25, Line 21 / 21%		$32,211,330	
21	Allocated FY 2021 Federal NOL Not Subject to Proration	(Line 18 / Line 19) * Line 20		$28,703,584	
22	Allocated FY 2021 Federal NOL Subject to Proration	(Line 17 / Line 19) * Line 20		$3,507,746	
23	Effective Tax Rate			21.00%	
24	Deferred Tax Benefit subject to proration	Line 22 * Line 23		$736,627	
25	Net Deferred Tax Reserve subject to proration	Line 7 + Line 24		$144,624	($955,805)
		(h)	(i)	(j)	(k)
	Proration Calculation	Number of Days in Month	Proration Percentage		
26	April	30	91.78%	$11,061	($73,104)
27	May	31	83.29%	$10,038	($66,339)
28	June	30	75.07%	$9,047	($59,792)
29	July	31	66.58%	$8,024	($53,028)
30	August	31	58.08%	$7,000	($46,263)
31	September	30	49.86%	$6,010	($39,716)
32	October	31	41.37%	$4,986	($32,951)
33	November	30	33.15%	$3,995	($26,405)
34	December	31	24.66%	$2,972	($19,640)
35	January	31	16.16%	$1,948	($12,875)
36	February	28	8.49%	$1,024	($6,765)
37	March	31	0.00%	$0	$0
38	Total	365		$66,105	($436,877)
39	Deferred Tax Without Proration	Line 25		$144,624	($955,805)
40	Average Deferred Tax without Proration	Line 39 × 0.5		$72,312	($477,903)
41	Proration Adjustment	Line 38 - Line 40		($6,208)	$41,025

Column Notes:

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

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

The Narragansett Electric Company
d/b/a National Grid
FY 2021 Electric ISR Revenue Requirement Plan
FY 2018 - 2021 Incremental Capital Investment Summary

Line No.			Fiscal Year 2018 (a)	Fiscal Year 2019 (b)	Fiscal Year 2020 (c)	Fiscal Year 2021 (d)
	Capital Investment					
1	ISR - Eligible Capital Investment	Col (a) = FY 2018 ISR Docket No.4682, Att MAL-1 P2, L3; Col (b)=FY 2019 ISR Docket No.4783, Att PCE-1 P3, Table 1; Col (c)=FY 2020 ISR Docket No.4915,Revised section 5, Att IS, page 11; Col (d)= Section 2, Chart 10, Column 2	$92,659,654	$111,243,061	$102,797,000	$110,494,000
2	Intangible Assest included in Total Allowed Discretionary Capital	Col (a) (c) = 0; Col (b) = FY 2019 ISR Docket No. 4783, Att. MAL-1,Page 30 of 38, Line13; Col (d) = Section 2, Chart 10, Column 2, VVO	$0	$3,460,626	$0	$1,000,000
3	ISR - Eligible Capital Additions included in Rate Base per RIPUC Docket No. 4770	Docket No. 4770, S. C. Att. 2, Sch 11-ELEC, P5, L1, Col (a) = Col(a)+Col(b); Col(b)=Col(c)+Col(d); Col(c)=Col(e), Col(d)=Col(j)+Col(k)	$74,843,000	$74,843,000	$31,184,583	$0
4	Incremental ISR Capital Investment (non-intangible)	Line 1 - Line 2 - Line 3	$17,816,654	$32,939,435	$71,612,417	$109,494,000
	Cost of Removal					
5	ISR - Eligible Cost of Removal	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)= FY 19 ISR Docket No. 4915, Revised Section 5: Attachment IS, Page 11, L4(c); Col(d)= Section 2, Chart 10, Column 3	$9,979,698	$7,949,082	$14,000,000	$11,700,000
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	$8,259,707	$7,848,009	$3,437,925	$205,400
7	Incremental Cost of Removal	Line 5 - Line 6	$1,719,991	$101,073	$10,562,075	$11,494,600
	Retirements					
8	ISR - Eligible Retirements/Actual	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)=FY 19 ISR Docket No. 4915, Revised Section 5: Attachment IS, Page 11, L7(c); Col (d)= Line 1(d)* Past 3 Year Average Retirement Rate	$15,206,748	$12,015,754	$29,278,786	$20,876,177
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	$20,451,820	$22,665,233	$9,928,809	$593,200
10	Incremental Retirements	Line 8 - Line 9	($5,245,072)	($10,649,479)	$19,349,978	$20,282,977
	Net NOL Position					
11	ISR - (NOL)/Utilization	Col (a) =FY 2018 ISR Docket No. 4682; Col (b) = FY 2019 ISR Docket No. 4783, Att PCE-1 P3, Table 2, Col (c)=FY 19 ISR Docket No. 4915, Revised Section 5: Attachment IS, Page 11, L10(c); Col (d)= Per Tax Department	($4,571,409)	$12,460,450	$3,822,834	$0
12	less: (NOL)/Utilization recovered in transmission rates	Quarterly average transmission plant allocator per Integrated Facilities Agreement (IFA) * Line 11	($1,572,911)	$4,263,209	$1,322,978	$0
13	Distribution-related (NOL)/Utilization	Maximum of (Line 11 - Line 12) or -Page 19 of 25, Line 10	($2,998,499)	$8,197,241	$2,499,856	$0
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	$0	$0	$1,462,980	$6,764,379
15	Incremental (NOL)/Utilization	Line 13 - Line 14	($2,998,499)	$8,197,241	$1,036,875	($6,764,379)

The Narragansett Electric Company
d/b/a National Grid
FY 2021 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)
							Jul & Aug 2017	12 Mths Aug 31 2018	12 Mths Aug 31 2019	12 Mths Aug 31 2020	12 Mths Aug 31 2021
1	Total Base Rate Plant DIT Provision						$2,580,654	$5,847,765	$4,355,117	$707,056	$3,826,291
2	Excess DIT Amortization								($3,074,665)	($3,074,665)	($3,074,665)
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
3	Total Base Rate Plant DIT Provision						$5,991,850	$3,183,499	($847,584)	($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	$3,665,930	$3,759,875	$3,863,190	$3,810,868		$3,665,930	$93,944	$103,315	($52,322)
6	Incremental FY 20			$7,070,156	$7,505,824	$7,882,743			$7,070,156	$435,667	$376,919
7	Incremental FY 21				$5,381,314	$6,273,774				$5,381,314	$892,460
8	TOTAL Plant DIT Provision	$4,261,399	$7,889,365	$15,011,341	$20,881,206	$22,040,125	$10,253,250	$6,811,464	$6,274,392	$5,321,810	$1,472,096
9	Distribution-related NOL						$2,998,499	($8,197,241)	($2,499,856)	$0	
10	Lesser of Distribution-related NOL or DIT Provision						$2,998,499	($8,197,241)	($2,499,856)	$0	

Line Notes:

1(f)	RIPUC Docket No. 4770, Supplemental Compliance Attachment 2, Schedule 11-ELEC, Page 11 of 20, Line 3
1(g)	RIPUC Docket No. 4770, Supplemental Compliance Attachment 2, Schedule 11-ELEC, Page 11 of 20, Line 7
1(h)	RIPUC Docket No. 4770, Supplemental Compliance Attachment 2, Schedule 11-ELEC, Page 11 of 20, Line 50
1(i)	RIPUC Docket No. 4770, Supplemental Compliance Attachment 2, Schedule 11-ELEC, Page 12 of 20, Line 41
1(j)	RIPUC Docket No. 4770, Supplemental Compliance Attachment 2, Schedule 11-ELEC, Page 12 of 20, Line 51
2(h)	RIPUC Docket No. 4770, Supplemental Compliance Attachment 2, Schedule 11-ELEC, Page 11 of 20, Line 51
2(i)&(j)	RIPUC Docket No. 4770, Electric Distribution Rate Changes for Rate Year 2, Att. 2, Sch. 11-ELEC, P.11 of 20, L. 51; P. 12 of 20, L. 42 & 52
3	Col(f) = Line1(f) + Line1(g)×7÷12 ; Col (g) = Line 1(g)×5÷12 + (Line 1(h)+ 2(h))×7÷12; Col (h) = (Line 1(h) + 2(h))×5÷12 + (Line1(i) +2(i))×7÷12; Col (i) = (Line 1(i) + 2(i))×5÷12 + (Line1(j
4(a)-7(e)	Cumulative DIT per vintage year ISR revenue requirement calculations (P.2, L.20+L.22; P.5, L.20+P.8,L.23; P.10, L.20; P.14, L.20)
4(f) -7(j)	Year over year change in cumulative DIT shown in Cols (a) through (d)
8	Sum of Lines 2 through 5
9	Page 18 of 25, Line 13
10	Lesser of Line 8 or Line 9

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

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

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

The Narragansett Electric Company
d/b/a National Grid
ISR Depreciation Rate per RIPUC Docket No. 4770

Line	Description	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
RIPUC Docket Nos. 4770/4780
Compliance Attachment 2
Schedule 6-ELEC
Page 1 of 5

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

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

Line No.	Description		Reference	Amount		less non-ISR eligible plant	ISR Eligible Amount
			(a)	(b)		(c)	(d)
1	Total Company Rate Year Distribution Depreciation Expense		Sum of Page 2, Line 16 and Line 17	$369,017	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	($48,792,358)	6		
7					7		
8				Per Book	8		
9	Test Year Depreciation Expense 12 Months Ended 06/30/17:			Amount	9		
10	Total Distribution Utility Plant 06/30/17		Page 4, Line 28, Column (e)	$2,141,474,644	10	($39,763,450)	$2,101,711,193
11	Less Non Depreciable Plant		Page 4, Line 26, Column (e)	($627,567,742)	11		($627,567,742)
12	Depreciable Utility Plant 6/30/17		Line 10 + Line 11	$1,513,906,902	12	($39,763,450)	$1,474,143,451
13					13		
14	Plus: Added Plant 2 Mos Ended 08/31/17		Schedule 11-ELEC, Page 6, Line 7	$12,473,833	14	$0	$12,473,833
15	Less: Streetlights retired in the 2 Mos Ended 08/31/17		Per Company Books	($1,057,011)	15	$0	($1,057,011)
16	Less: Retired Plant 2 Months Ended 08/31/17	1/	Line 14 x Retirement Rate	($3,699,739)	16	$0	($3,699,739)
17	Depreciable Utility Plant 08/31/17		Line 12 + Line 14 + Line 16	$1,521,623,985	17	($39,763,450)	$1,481,860,535
18					18		
19	Average Depreciable Plant from 06/30/17 to 08/31/17		(Line 12 + Line 17)/2	$1,517,765,443	19		$1,478,001,993
20					20		
21	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.40%	21		3.40%
22					22		
23	Book Depreciation Reserve 06/30/17		Page 5, Line 69, Column (e)	$652,405,159	23		
24	Plus: Book Depreciation Expense excluding Streetlight Retirement		1/6 of (Line 19 excl. Line 15 x Line 21)	$8,603,666	24		$8,381,334
25	Less: Streetlights retired in the 2 Mos Ended 08/31/17 and Dep. for 2 Mos		1/12 of (Line 15 x SL Dep Rate)	($1,307)	25		($1,307)
26	Less: Net Cost of Removal/(Salvage)	2/	Line 14 x Cost of Removal Rate	($1,281,063)	26		
27	Less: Retired Plant		Line 16	($3,699,739)	27		
28	Book Depreciation Reserve 08/31/17		Sum of Line 23 through Line 27	$656,026,715	28		
29					29		
30	Depreciation Expense 12 Months Ended 08/31/18				30		
31	Total Utility Plant 08/31/17		Line 10 + Line 14 + Line 15 + Line 16	$2,149,191,727	31	($39,763,450)	$2,109,428,277
32	Less Non Depreciable Plant		Line 11	($627,567,742)	32	$0	($627,567,742)
33	Depreciable Utility Plant 08/31/17		Line 31 + Line 32	$1,521,623,985	33	($39,763,450)	$1,481,860,535
34					34		
35	Plus: Plant Added in 12 Months Ended 08/31/18		Schedule 11-ELEC, Page 6, Line 14	$74,843,000	35	$0	$74,843,000
36	Less: Plant Retired in 12 Months Ended 08/31/18	1/	Line 35 x Retirement rate	($22,198,434)	36	$0	($22,198,434)
37	Depreciable Utility Plant 08/31/18		Sum of Line 33 through Line 36	$1,574,268,551	37	($39,763,450)	$1,534,505,101
38					38		
39	Average Depreciable Plant for 12 Months Ended 08/31/18		(Line 33 + Line 37)/2	$1,547,946,268	39	($39,763,450)	$1,508,182,818
40					40		
41	Composite Book Rate %		As Approved in RIPUC Docket No. 4323	3.40%	41		3.40%
42					42		
43	Book Depreciation Reserve 08/31/17		Line 28	$656,026,715	43		
44	Plus: Book Depreciation 08/31/18		Line 39 x Line 41	$52,630,173	44		$51,278,216
45	Less: Net Cost of Removal/(Salvage)	2/	Line 35 x Cost of Removal Rate	($7,686,376)	45		
46	Less: Retired Plant		Line 36	($22,198,434)	46		
47	Book Depreciation Reserve 08/31/18		Sum of Line 43 through Line 46	$678,772,079	47		

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

Compliance Attachment 2
Schedule 6-ELEC
Page 2 of 5

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

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

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

Line No.	Description		Reference	Amount		less non-ISR eligible plant	ISR Eligible Amount
			(a)	(b)		(c)	(d)
1	**Rate Year Depreciation Expense 12 Months Ended 08/31/19:**				1		
2	Total Utility Plant 08/31/18		Page 1, Line 31 + Line 35 + Line 36	$44,557,107	2	($39,763,450)	$2,162,072,843
3	Less Non-Depreciable Plant		Page 1, Line 11	($52,243,483)	3	$0	($627,567,742)
4	Depreciable Utility Plant 08/31/18		Line 2 + Line 3	($7,686,376)	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	$46,855,963	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	$19,584,794	11	($40,712,337)	$1,560,827,384
12					12		
13	Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%	13		3.16%
14					14		
15	Book Depreciation Reserve 08/31/18		Page 1, Line 47	$678,772,079	15		
16	Plus: Book Depreciation Expense		Line 11 x Line 13	$616,026	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	$648,178,975	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	$99,099,446	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	($528,468,296)	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	($527,061,496)	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	($527,764,896)	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	$648,178,975	36		
37	Plus: Book Depreciation Expense		Line 32 x Line 34	($16,600,485)	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	$630,532,880	41	$ 367,810,847	$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	$100,506,246	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	($527,061,496)	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	($525,654,696)	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	($526,358,096)	53	($43,771,424)	$1,587,149,667
54					54		
55	Proposed Composite Rate %		Page 4, Line 18, Columnumn (f)	3.15%	55		3.16%
56					56		
57	Book Depreciation Reserve 08/31/20		Line 41	$630,532,880	57		
58	Plus: Book Depreciation Expense		Line 53 x Line 55	($16,556,235)	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	$612,931,036	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 2021 ISR Property Tax Recovery Adjustment
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		End of FY 2018	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2019
1	Plant In Service	$1,595,499	$111,243	$3,137	$114,380		($12,016)		$1,697,863
2	Accumulated Depr	$672,116				$52,896	($12,016)	($7,949)	$705,047
3	Net Plant	$923,383							$992,816
4	Property Tax Expense	$30,354							$32,077
5	Effective Prop tax Rate	3.29%							3.23%
	Effective tax Rate Calculation	End of FY 2019	ISR Additions	Non-ISR Add's	Total Add's	Bk Depr (1)	Retirements	COR	End of FY 2020
6	Plant In Service	$1,697,863	$102,797	$5,901	$108,698		($29,279)		$1,777,282
7	Accumulated Depr	$705,047				$54,068	($29,279)	($14,000)	$715,836
8	Net Plant	$992,816							$1,061,446
9	Property Tax Expense	$32,077							$34,892
10	Effective Prop tax Rate	3.23%							3.29%
	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	$1,777,282	$110,494	$3,137	$113,631		($20,876)		$1,870,036
12	Accumulated Depr	$715,836				$56,696	($20,876)	($11,700)	$739,955
13	Net Plant	$1,061,446							$1,130,081
14	Property Tax Expense	$34,892							$36,512
15	Effective Prop tax Rate	3.29%							3.23%

Line	**Property Tax Recovery Calculation**	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cumulative Increm. ISR Prop. Tax for FY2018				Cumulative Increm. ISR Prop. Tax for FY2019 1st 5 months		
16	Incremental ISR Additions		$92,660				$111,243	
17	Book Depreciation: base allowance on ISR eligible plant		($43,032)				($43,032)	
18	Book Depreciation: current year ISR additions		($1,317)				($1,628)	
19	COR		$9,980				$7,949	
20	Net Plant Additions		$58,291				$74,532	
21	RY Effective Tax Rate		3.98%					
22	ISR Property Tax Recovery on FY 2014 vintage investment			$62		5 month		$0
23	ISR Property Tax Recovery on FY 2015 vintage investment			$1,366				$0
24	ISR Property Tax Recovery on FY 2016 vintage investment			$1,335				8.23%
25	ISR Property Tax Recovery on FY 2017 vintage investment			$1,521				$0
26	ISR Property Tax Recovery on FY 2018 vintage investment			$2,321				$0
27	ISR Property Tax Recovery on FY 2019 vintage investment							$0
28	Total Property Tax due to ISR			6,606				0
29	ISR Year Effective Tax Rate	3.29%				3.23%		
30	RY Effective Tax Rate	3.98%	-0.69%			0.00%	3.23%	
31	RY Effective Tax Rate 5 mos for FY 2019		-0.69%			5 month	1.35%	
32	RY Net Plant times 5 mo rate	$746,900	* -0.69%	($5,191)		$746,900	* 1.35%	$10,055
33	FY 2014 Net Adds times ISR Year Effective Tax rate	$1,566	* -0.69%	($11)		$1,232	* 1.35%	$17
34	FY 2015 Net Adds times ISR Year Effective Tax rate	$34,308	* -0.69%	($238)		$32,324	* 1.35%	$435
35	FY 2016 Net Adds times ISR Year Effective Tax rate	$33,535	* -0.69%	($233)		$32,090	* 1.35%	$432
36	FY 2017 Net Adds times ISR Year Effective Tax rate	$38,200	* -0.69%	($265)		$37,040	* 1.35%	$499
37	FY 2018 Net Adds times ISR Year Effective Tax rate	$58,291	* -0.69%	($405)		$55,850	4455710700.00%	$752
38	FY 2019 Net Adds times ISR Year Effective Tax rate					$74,532	($44,557,107)	$1,003
39	Total Property Tax due to rate differential			($6,343)				$13,193
40	Total ISR Property Tax Recovery			$263				$13,193

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

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Cumulative Increm. ISR Prop. Tax for FY2019 7 months				Cumulative Increm. ISR Prop. Tax for FY2020				Cumulative Increm. ISR Prop. Tax for FY2021		
41	Incremental ISR Additions		$36,400				$71,612				$110,494	
42	Book Depreciation: base allowance on ISR eligible plant		$0				$0				$0	
43	Book Depreciation: current year ISR additions		($999)				($826)				($1,481)	
44	COR		$101				$10,562				$11,495	
45	Net Plant Additions		$35,502				$81,349				$120,508	
46	RY Effective Tax Rate		3.28%				3.38%				3.58%	
47	ISR Property Tax Recovery on non-ISR		1.91%	$0				($77)				($153)
48	ISR Property Tax Recovery on FY 2018 Net Incremental			$352				$598				$606
49	ISR Property Tax Recovery on FY 2019 Net Incremental			$679				$1,138				$1,136
50	ISR Property Tax Recovery on FY 2020 Net Incremental							$2,752				$2,851
51	ISR Property Tax Recovery on FY 2021 vintage investment											$4,310
52	ISR Year Effective Tax Rate	3.23%				3.29%				3.23%		
53	RY Effective Tax Rate	3.28%	-0.05%			3.38%	-0.10%			3.58%	-0.35%	
54	RY Effective Tax Rate 7 mos for FY 2019		-0.03% 7 mos				-0.10%				-0.35%	
55	RY Net Plant times Rate Difference	$930,873	* -0.03%	($279)		$902,404	* -0.1%	($902)		$853,576	* -0.35%	($2,952)
56	Non-ISR plant times rate difference					($2,269)	* -0.1%	$2		($4,269)	* -0.35%	$15
57	FY 2018 Net Incremental times rate difference	$18,393	* -0.03%	($6)		$17,664	* -0.1%	($18)		$16,935	* -0.35%	($59)
58	FY 2019 Net Incremental times rate difference	$35,502	* -0.03%	($11)		$33,630	* -0.1%	($34)		$31,759	* -0.35%	($110)
59	FY 2020 Net Incremental times rate difference					$81,349	* -0.1%	($81)		$79,697	* -0.35%	($276)
60	FY 2021 Net Adds times rate difference									$120,508	* -0.35%	($417)
61	Total Property Tax due to rate differential			($295)				($1,033)				($3,798)
62	Total ISR Property Tax Recovery			$736				$3,378				$4,952

Line Notes

1(a) - 5(h)	Per Docket No. 4783, FY2019 Rec, Part 2 -Attachment MAL-2, Page 13, Line 1(a)~Line 5(h)
6(a) - 10(a)	=1 ~ 5(h)
6(b) - 6(d)	Docket No. 4915, R. S. 5: Att. 1S, Page 16 of 19, L 7(b) through L 7(d)
6(f), 7(f)	Docket No. 4915, R. S. 5: Att. 1S, Page 16 of 19, L 7(f)
6(h)	Sum of L6 C(a), L6 C(d), L6 C(f)
7(e)	[Docket 4770, C. Att. 2, Sch 6-ELEC, P2: L (16(b)+ L17(b)) x 5/12+ L (37(b) + 38(b)) x 7/12] +((Page 2 of 25, L 6(a)+ Page 5 of 25, L 6(a)) x 0.0316+,Page 8 of 25, L29(f))/1000 +Page 10 of 25, L6(a) x0.0316x0.5/1000
7(g)	Docket No. 4915, R. S. 5: Att. 1S, Page 16 of 19, L 8(g)
7(h)	Sum of L7 C(a), L7 C(e), L7 C(f), L7 C(g)
8(h)	6(h)-7(h)
9(h)	8(h)*10(h)
10(h)	=5(a)
11(a) - 15(a)	=6(h)~10(h)
11(b)	Page 18 of 25, Line 1, Col (d)
11(c)	Line 1(c), estimated based on FY19 actual non-ISR addition
11(d)	11(b) + (c)
11(f), 12(f)	- Page 18 of 25, Line 8(d)
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 (37(b)+38(b)) x 5/12 + L (58(b) + 59(b))x 7/12 +((Page 2 of 25, L 6(a)+ Page 5 of 25, L 6(a)+Page 10 of 25, L6(a)) x 0.0316+Page 8 of 25, L29(i))/1000 +Page 14 of 25, L6(a) x0.0316x0.5/1000
12(g)	Page 18 of 25, Line 5(d)
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), estimated based on FY19 actual property tax rate
16(b) - 40(g)	Docket No. 4783, FY19 Rec, Part 2 -Attachment MAL-2, Page 12, Line 6(a)~Line 30(g)
41(a) - 62(c)	Docket No. 4783, FY19 Rec, Part 2 -Attachment MAL-2, Page 12, Line 31(a)~Line 50(c)
55(a)	Docket No. 4770, Com. Att. 2, Sch 6-E, P2, (L9 - L20) ÷ 1000
55(c)(g)(k)	col (c)= 55(a)*54(b), Col (g)=55(e) *54(f), Col (K)=55(i) *54(j)

Line Notes

41(f)	Page 10 of 25, Line 4(a) ÷1000
42(f)	FY20 depreciation is reflected in the NBV at 55(e)
43(f)	- Page 10 of 25, Line 16(a) ÷1000
44(f)	Page 10 of 25, Line 10(a) ÷1000
45(f)	Sum of Lines 41(f) through 44(f)
46(f)	Docket No. 4770, R. Rebuttal Att. 1, Sch 7-ELEC, P.2, L 3 (c) / [Sch 6-E, P2, ((L9 - L20)*5/12+ (L30-L41)*7/12]
47(g)	57(e) ×46(f)
48(g)	58(e) ×46(f)
49(g)	58(e) ×46(f)
50(g)	59(e) ×46(f)
52(e)	=10(h)
53(e)	=46(f)
53(f)	52(e) -53(e)
54(f)	=53(f)
55(e)	=55(a)
56(e)	Docket No. 4770, R. Rebuttal Att. 1, Sch 11-ELEC, P.5, L.8(e) + L.8(g)
56(g)	56(e) x54(f)
56(e)	=57(a)-Page 2 of 25, Line 16(c)
57(g)	57(e) x54(f)
58(e)	58(a)- (Page 5 of 25, Line 16(b) + Page 8 of 25, Line 29(f))/1000
58(g)	58(e) x54(f)
59(e)	=45(f)
59(g)	59(e) x54(f)
61(g)	Sum of Lines 55(g) through 60(g)
62(g)	Sum of Lines 47(g) through 51(g)&61(g)

Line Notes

41(j)	Page 14 of 25, Line 4(a) ÷1000
42(j)	FY21 depreciation is reflected in the NBV at 55(i)
43(j)	- Page 14 of 25, Line 16(a) ÷1000
44(j)	Page 14 of 25, Line 10(a) ÷1000
45(j)	Sum of Lines 41(j) through 44(j)
46(j)	Docket No. 4770, R. Rebuttal Att. 1, Sch 7-ELEC, P.2, L 3 (e) / [Sch 6-E, P2, ((L30 - L41)*5/12+ (L51-L62)*7/12]
47(k)	57(i) ×46(j)
49(k)	58(i) ×46(j)
50(k)	59(i) ×46(j)
51(k)	60(f)×46(j)
52(i)	=15(h)
53(i)	=46(j)
53(j)	52(i) -53(i)
54(j)	=53(j)
55(i)	=55(a)
56(i)	Docket No. 4770, R. Rebuttal Att. 1, Sch 11-ELEC, P.5, L.8(h) + L.8(j)
56(k)	(j)x7 mos(k)
57(i)	=57(e) -Page 2 of 25, Line 16(d)
57(k)	57(i) x54(j)
58(i)	58(e) - (Page 5 of 25, Line 16(c) + Page 8 of 25, Line 29(i))/1000
58(k)	58(i) x54(j)
59(i)	59(e) -Page 10 of 25, Line 16(b)/1000
59(k)	59(i) x54(j)
60(i)	=45(j)
60(k)	60(i) x54(j)
61(k)	Sum of Lines 55(k) through 60(k)
62(k)	Sum of Lines 47(k) through 51(k)&61(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						
22	Weighted Average Cost of Capital as approved in RIPUC Docket No. 4770 effective September 1, 2018					
23		Ratio	Rate	Weighted Rate	Taxes	Return
24	Long Term Debt	48.35%	4.62%	2.23%		2.23%
25	Short Term Debt	0.60%	1.76%	0.01%		0.01%
26	Preferred Stock	0.10%	4.50%	0.00%		0.00%
27	Common Equity	50.95%	9.28%	4.73%	1.26%	5.99%
28		100.00%		6.97%	1.26%	8.23%
29						
30	(d) - Column (c) x 21% divided by (1 - 21%)					
31						
32	FY18 Blended Rate	Line 7(e) x 75% + Line 17(e) x 25%				9.36%
33						
34	FY19 Blended Rate	Line 17 x 5 ÷ 12 + Line 28 x 7 ÷ 12				8.31%
35						
36	FY20 and after Rate	Line 28(e)				8.23%

Section 6
Rate Design

Section 6

Rate Design and Rates
FY 2021 Electric ISR Plan Annual Filing

The Narragansett Electric Company
Infrastructure, Safety and Reliability Plan Factors Calculations - Summary
Summary of Proposed Factors
(for the 12 months beginning April 1, 2020)

		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	$0.00212	$0.00212	$0.00169	$0.00086	$0.00086	$0.01070	$0.00026
(2)	O&M Factor per kW	n/a	n/a	n/a	$0.05	n/a	n/a	n/a
(3)	CapEx kWh Charge	$0.00384	$0.00328	n/a	n/a	n/a	$0.00441	$0.00025
(4)	CapEx kW Charge	n/a	n/a	$0.94	$0.91	$0.91	n/a	n/a
(5)	Back-Up Service CapEx kW Charge	n/a	n/a	n/a	$0.09	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
FY21 Proposed Operations & Maintenance Factors
(for the 12 months beginning April 1, 2020)

		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)	FY2021 Forecasted Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense	$12,091,633						
(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	$12,091,633	$6,187,371	$1,345,521	$2,068,748	$1,927,057	$556,918	$6,018
(5)	Forecasted kWh - April 2020 through March 2021	7,067,418,953	2,918,498,691	631,768,891	1,223,505,460	2,219,223,244	52,010,032	22,412,636
(6)	Proposed Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kWh		$0.00212	$0.00212	$0.00169	$0.00086	$0.01070	$0.00026

(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) ÷ Line (2) Total Column
(4) Line (1) Total Column x Line (3)
(5) per Company forecasts
(6) Line (4) ÷ Line (5), truncated to 5 decimal places

The Narragansett Electric Company
FY21 Proposed CapEx Factors
(for the 12 months beginning April 1, 2020)

		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)	FY2021 Capital Investment Component of Revenue Requirement	$20,211,188						
(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	$20,211,188	$11,220,426	$2,078,126	$3,245,798	$3,431,253	$229,831	$5,754
(5)	Forecasted kWh - April 2020 through March 2021	7,067,418,953	2,918,498,691	631,768,891	1,223,505,460	2,219,223,244	52,010,032	22,412,636
(6)	Proposed CapEx Factor - kWh charge		$0.00384	$0.00328	n/a	n/a	$0.00441	$0.00025
(7)	Forecasted kW - April 2020 through March 2021				3,433,286	3,738,202		
(8)	Proposed CapEx Factor - kW Charge		n/a	n/a	$0.94	$0.91	n/a	n/a

(1) per Section 5: Attachment 1, page 1, Line (12), Column (b)
(2) RIPUC 4770, Compliance Attachment 6, (Schedule 1A), page 1, Line 9
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column 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	$1,927,057
(2)	Forecasted kW - April 2020 through March 2021	3,738,202
(3)	Vegetation Management (VM) and Inspection & Maintenance (I&M) O&M Expense Charge per kW	$0.51
(4)	Proposed Discounted O&M kW Factor Charge effective 4/1/2020	$0.05
	CapEx Factors	
(5)	Proposed CapEx kW Factor Charge effective 4/01/2020	$0.91
(6)	Proposed Discounted CapEx kW Factor Charge effective 4/1/2020	$0.09

(1) Page 2, Line (4)
(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)
(6) Line (5) x .10, truncated to two decimal places

Section 7

Bill Impacts
FY 2021 Electric ISR Plan Annual Filing

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

Monthly kWh (a)	Rates Effective October 1, 2019: Delivery Services (b)	Supply Services (c)	GET (d)	Total (e) = (a) + (b) + (c)	Proposed Rates effective April 1, 2020: Delivery Services (f)	Supply Services (g)	GET (h)	Total (i) = (f) + (g) + (h)	$ Increase (Decrease): Delivery Services (j) = (f) - (b)	Supply Services (k) = (g) - (c)	GET (l) = (h) - (d)	Total (m) = (j) + (k) + (l)	Increase (Decrease) % of Total Bill: Delivery Services (n) = (j) / (e)	Supply Services (o) = (g) / (e)	GET (p) = (h) / (e)	Total (q) = (m) / (e)	Percentage of Customers (r)
150	$23.60	$16.44	$1.67	$41.71	$24.01	$16.44	$1.69	$42.14	$0.41	$0.00	$0.02	$0.43	1.0%	0.0%	0.0%	1.0%	30.1%
300	$38.50	$32.87	$2.97	$74.34	$39.33	$32.87	$3.01	$75.21	$0.83	$0.00	$0.04	$0.87	1.1%	0.0%	0.1%	1.2%	12.9%
400	$48.43	$43.83	$3.84	$96.10	$49.54	$43.83	$3.89	$97.26	$1.11	$0.00	$0.05	$1.16	1.2%	0.0%	0.1%	1.2%	11.6%
500	$58.37	$54.79	$4.72	$117.88	$59.75	$54.79	$4.77	$119.31	$1.38	$0.00	$0.05	$1.43	1.2%	0.0%	0.0%	1.2%	9.6%
600	$68.30	$65.74	$5.59	$139.63	$69.95	$65.74	$5.65	$141.34	$1.65	$0.00	$0.06	$1.71	1.2%	0.0%	0.0%	1.2%	7.7%
700	$78.23	$76.70	$6.46	$161.39	$80.16	$76.70	$6.54	$163.40	$1.93	$0.00	$0.08	$2.01	1.2%	0.0%	0.0%	1.2%	19.0%
1,200	$127.90	$131.48	$10.81	$270.19	$131.21	$131.48	$10.95	$273.64	$3.31	$0.00	$0.14	$3.45	1.2%	0.0%	0.1%	1.3%	6.8%
2,000	$207.36	$219.14	$17.77	$444.27	$212.88	$219.14	$18.00	$450.02	$5.52	$0.00	$0.23	$5.75	1.2%	0.0%	0.1%	1.3%	2.3%

		Rates Effective October 1, 2019 (s)	Proposed Rates effective April 1, 2020 (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		$1.90	$1.90	RE Growth Program
(4) Distribution Charge (per kWh)		$0.04496	$0.04496	Distribution Energy Charge
(5) Operating & Maintenance Expense Charge		$0.00204	$0.00212	
(6) Operating & Maintenance Expense Reconciliation Factor		($0.00008)	($0.00008)	
(7) FY21 CapEx Factor Charge		$0.00116	$0.00384	
(8) CapEx Reconciliation Factor		$0.00071	$0.00071	
(9) Revenue Decoupling Adjustment Factor		($0.00061)	($0.00061)	
(10) Pension Adjustment Factor		($0.00005)	($0.00005)	
(11) Storm Fund Replenishment Factor		$0.00288	$0.00288	
(12) Arrearage Management Adjustment Factor		$0.00010	$0.00010	
(13) Low Income Discount Recovery Factor		$0.00152	$0.00152	
(14) Long-term Contracting for Renewable Energy Charge		$0.00711	$0.00711	Renewable Energy Distribution Charge
(15) Net Metering Charge		$0.00068	$0.00068	
(16) Base Transmission Charge		$0.03034	$0.03034	Transmission Charge
(17) Transmission Adjustment Factor		($0.00217)	($0.00217)	
(18) Transmission Uncollectible Factor		$0.00037	$0.00037	
(19) Base Transition Charge		($0.00093)	($0.00093)	Transition Charge
(20) Transition Adjustment		($0.00021)	($0.00021)	
(21) Energy Efficiency Program Charge		$0.01151	$0.01151	Energy Efficiency Programs
(22) Standard Offer Service Base Charge		$0.10884	$0.10884	Supply Services Energy Charge
(23) SOS Adjustment Factor		($0.00223)	($0.00223)	
(24) SOS Adminstrative Cost Adjustment Factor		$0.00233	$0.00233	
(25) Renewable Energy Standard Charge		$0.00063	$0.00063	
Line Item on Bill				
(26) Customer Charge		$6.00	$6.00	
(27) LIHEAP Enhancement Charge		$0.80	$0.80	
(28) RE Growth Program		$1.90	$1.90	
(29) Transmission Charge	kWh x	$0.02854	$0.02854	
(30) Distribution Energy Charge	kWh x	$0.05263	$0.05539	
(31) Transition Charge	kWh x	($0.00114)	($0.00114)	
(32) Energy Efficiency Programs	kWh x	$0.01151	$0.01151	
(33) Renewable Energy Distribution Charge	kWh x	$0.00779	$0.00779	
(34) Supply Services Energy Charge	kWh x	$0.10957	$0.10957	

Column (s): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2019, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2019
Column (t): Line (5) per Section 6, Page 1, Line (1), Column (a); Line (7) per Section 6, Page 1, Line (3), Column (a)

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, 2019						Proposed Rates effective April 1, 2020						$ 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-.25	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.25	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) ÷ [(b)+(d)]	(s) = (o) ÷ (c)	(t) = (p) ÷ (f)	(u) = (q) ÷ (g)	(v)
150	$21.37	$16.44	($9.45)	$28.36	$1.18	$29.54	$21.79	$16.44	($9.56)	$28.67	$1.19	$29.86	$0.31	$0.00	$0.01	$0.32	1.0%	0.0%	0.0%	1.1%	32.1%
300	$36.04	$32.87	($17.23)	$51.68	$2.15	$53.83	$36.87	$32.87	($17.44)	$52.30	$2.18	$54.48	$0.62	$0.00	$0.03	$0.65	1.2%	0.0%	0.1%	1.2%	15.4%
400	$45.82	$43.83	($22.41)	$67.24	$2.80	$70.04	$46.93	$43.83	($22.69)	$68.07	$2.84	$70.91	$0.83	$0.00	$0.04	$0.87	1.2%	0.0%	0.1%	1.2%	12.5%
500	$55.61	$54.79	($27.60)	$82.80	$3.45	$86.25	$56.99	$54.79	($27.95)	$83.83	$3.49	$87.32	$1.03	$0.00	$0.04	$1.07	1.2%	0.0%	0.0%	1.2%	9.6%
600	$65.39	$65.74	($32.78)	$98.35	$4.10	$102.45	$67.04	$65.74	($33.20)	$99.58	$4.15	$103.73	$1.23	$0.00	$0.05	$1.28	1.2%	0.0%	0.0%	1.2%	7.2%
700	$75.17	$76.70	($37.97)	$113.90	$4.75	$118.65	$77.10	$76.70	($38.45)	$115.35	$4.81	$120.16	$1.45	$0.00	$0.06	$1.51	1.2%	0.0%	0.1%	1.3%	16.4%
1,200	$124.07	$131.48	($63.89)	$191.66	$7.99	$199.65	$127.38	$131.48	($64.72)	$194.14	$8.09	$202.23	$2.48	$0.00	$0.10	$2.58	1.2%	0.0%	0.1%	1.3%	5.2%
2,000	$202.32	$219.14	($105.37)	$316.09	$13.17	$329.26	$207.84	$219.14	($106.75)	$320.23	$13.34	$333.57	$4.14	$0.00	$0.17	$4.31	1.3%	0.0%	0.1%	1.3%	1.6%

	Rates Effective October 1, 2019	Proposed Rates effective April 1, 2020	Line Item on Bill
	(w)	(x)	
(1) Distribution Customer Charge	$4.00	$4.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$1.90	$1.90	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04496	$0.04496	Distribution Energy Charge
(5) Operating & Maintenance Expense Charge	$0.00204	$0.00212	
(6) Operating & Maintenance Expense Reconciliation Factor	($0.00008)	($0.00008)	
(7) FY21 CapEx Factor Charge	$0.00116	$0.00384	
(8) CapEx Reconciliation Factor	$0.00071	$0.00071	
(9) Revenue Decoupling Adjustment Factor	($0.00061)	($0.00061)	
(10) Pension Adjustment Factor	($0.00005)	($0.00005)	
(11) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12) Arrearage Management Adjustment Factor	$0.00010	$0.00010	
(13) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(14) Long-term Contracting for Renewable Energy Charge	$0.00711	$0.00711	Renewable Energy Distribution Charge
(15) Net Metering Charge	$0.00068	$0.00068	
(16) Base Transmission Charge	$0.03034	$0.03034	Transmission Charge
(17) Transmission Adjustment Factor	($0.00217)	($0.00217)	
(18) Transmission Uncollectible Factor	$0.00037	$0.00037	
(19) Base Transition Charge	($0.00093)	($0.00093)	Transition Charge
(20) Transition Adjustment	($0.00021)	($0.00021)	
(21) Energy Efficiency Program Charge	$0.01151	$0.01151	Energy Efficiency Programs
(22) Standard Offer Service Base Charge	$0.10884	$0.10884	Supply Services Energy Charge
(23) SOS Adjustment Factor	($0.00223)	($0.00223)	
(24) SOS Adminstrative Cost Adjustment Factor	$0.00233	$0.00233	
(25) Renewable Energy Standard Charge	$0.00063	$0.00063	
Line Item on Bill			
(26) Customer Charge	$4.00	$4.00	
(27) LIHEAP Enhancement Charge	$0.80	$0.80	
(28) RE Growth Program	$1.90	$1.90	
(29) Transmission Charge	$0.02854	$0.02854	
(30) Distribution Energy Charge	$0.05111	$0.05387	
(31) Transition Charge	($0.00114)	($0.00114)	
(32) Energy Efficiency Programs	$0.01151	$0.01151	
(33) Renewable Energy Distribution Charge	$0.00779	$0.00779	
(34) Supply Services Energy Charge	$0.10957	$0.10957	
(35) Discount percentage	25%	25%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2019, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2019
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a); Line (8) per Section 6, Page 1, Line (3), Column (a)

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, 2019						Proposed Rates effective April 1, 2020						$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	Low Income Discount	Discounted Total	GET	Total	Delivery Services	Supply Services	GET	Total	Delivery Services	Supply Services	GET	Total	of Customers
(a)	(b)	(c)	(d) = [(b)+(c)] x-.30	(e) = (b) + (c) + (d)	(f)	(g) = (e) + (f)	(h)	(i)	(j) = [(h)+(i)] x-.30	(k) = (h) + (i) + (j)	(l)	(m) = (k) + (l)	(n) = [(h)+(j)] - [(b)+(d)]	(o) = (i) - (c)	(p) = (l) - (f)	(q) = (n) + (o) + (p)	(r) = (n) ÷ [(b)+(d)]	(s) = (o) ÷ (c)	(t) = (p) ÷ (f)	(u) = (q) ÷ (g)	(v)
150	$21.37	$16.44	($11.34)	$26.47	$1.10	$27.57	$21.79	$16.44	($11.47)	$26.76	$1.12	$27.88	$0.29	$0.00	$0.02	$0.31	1.1%	0.0%	0.1%	1.1%	32.1%
300	$36.04	$32.87	($20.67)	$48.24	$2.01	$50.25	$36.87	$32.87	($20.92)	$48.82	$2.03	$50.85	$0.58	$0.00	$0.02	$0.60	1.2%	0.0%	0.0%	1.2%	15.4%
400	$45.82	$43.83	($26.90)	$62.75	$2.61	$65.36	$46.93	$43.83	($27.23)	$63.53	$2.65	$66.18	$0.78	$0.00	$0.04	$0.82	1.2%	0.0%	0.1%	1.3%	12.5%
500	$55.61	$54.79	($33.12)	$77.28	$3.22	$80.50	$56.99	$54.79	($33.53)	$78.25	$3.26	$81.51	$0.97	$0.00	$0.04	$1.01	1.2%	0.0%	0.0%	1.3%	9.6%
600	$65.39	$65.74	($39.34)	$91.79	$3.82	$95.61	$67.04	$65.74	($39.83)	$92.95	$3.87	$96.82	$1.16	$0.00	$0.05	$1.21	1.2%	0.0%	0.1%	1.3%	7.2%
700	$75.17	$76.70	($45.56)	$106.31	$4.43	$110.74	$77.10	$76.70	($46.14)	$107.66	$4.49	$112.15	$1.35	$0.00	$0.06	$1.41	1.2%	0.0%	0.1%	1.3%	16.4%
1,200	$124.07	$131.48	($76.67)	$178.88	$7.45	$186.33	$127.38	$131.48	($77.66)	$181.20	$7.55	$188.75	$2.32	$0.00	$0.10	$2.42	1.2%	0.0%	0.1%	1.3%	5.2%
2,000	$202.32	$219.14	($126.44)	$295.02	$12.29	$307.31	$207.84	$219.14	($128.09)	$298.89	$12.45	$311.34	$3.87	$0.00	$0.16	$4.03	1.3%	0.0%	0.1%	1.3%	1.6%

	Rates Effective October 1, 2019 (w)	Proposed Rates effective April 1, 2020 (x)	Line Item on Bill
(1) Distribution Customer Charge	$4.00	$4.00	Customer Charge
(2) LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3) Renewable Energy Growth Program Charge	$1.90	$1.90	RE Growth Program
(4) Distribution Charge (per kWh)	$0.04496	$0.04496	Distribution Energy Charge
(5) Operating & Maintenance Expense Charge	$0.00204	$0.00212	
(6) Operating & Maintenance Expense Reconciliation Factor	($0.00008)	($0.00008)	
(7) FY21 CapEx Factor Charge	$0.00116	$0.00384	
(8) CapEx Reconciliation Factor	$0.00071	$0.00071	
(9) Revenue Decoupling Adjustment Factor	($0.00061)	($0.00061)	
(10) Pension Adjustment Factor	($0.00005)	($0.00005)	
(11) Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12) Arrearage Management Adjustment Factor	$0.00010	$0.00010	
(13) Low Income Discount Recovery Factor	$0.00000	$0.00000	
(14) Long-term Contracting for Renewable Energy Charge	$0.00711	$0.00711	Renewable Energy Distribution Charge
(15) Net Metering Charge	$0.00068	$0.00068	
(16) Base Transmission Charge	$0.03034	$0.03034	Transmission Charge
(17) Transmission Adjustment Factor	($0.00217)	($0.00217)	
(18) Transmission Uncollectible Factor	$0.00037	$0.00037	
(19) Base Transition Charge	($0.00093)	($0.00093)	Transition Charge
(20) Transition Adjustment	($0.00021)	($0.00021)	
(21) Energy Efficiency Program Charge	$0.01151	$0.01151	Energy Efficiency Programs
(22) Standard Offer Service Base Charge	$0.10884	$0.10884	Supply Services Energy Charge
(23) SOS Adjustment Factor	($0.00223)	($0.00223)	
(24) SOS Adminstrative Cost Adjustment Factor	$0.00233	$0.00233	
(25) Renewable Energy Standard Charge	$0.00063	$0.00063	
Line Item on Bill			
(26) Customer Charge	$4.00	$4.00	
(27) LIHEAP Enhancement Charge	$0.80	$0.80	
(28) RE Growth Program	$1.90	$1.90	
(29) Transmission Charge	$0.02854	$0.02854	
(30) Distribution Energy Charge	$0.05111	$0.05387	
(31) Transition Charge	($0.00114)	($0.00114)	
(32) Energy Efficiency Programs	$0.01151	$0.01151	
(33) Renewable Energy Distribution Charge	$0.00779	$0.00779	
(34) Supply Services Energy Charge	$0.10957	$0.10957	
(35) Discount percentage	30%	30%	

Column (w): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2019, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2019
Column (x): Line (5) per Section 6, Page 1, Line (1), Column (a); Line (8) per Section 6, Page 1, Line (3), Column (a)

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, 2019				Proposed Rates effective April 1, 2020				$ Increase (Decrease)				Increase (Decrease) % of Total Bill				Percentage
Monthly kWh (a)	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)	of Customers (n)
250	$37.43	$25.62	$2.63	$65.68	$38.01	$25.62	$2.65	$66.28	$0.58	$0.00	$0.02	$0.60	0.9%	0.0%	0.0%	0.9%	56.3%
500	$61.12	$51.24	$4.68	$117.04	$62.27	$51.24	$4.73	$118.24	$1.15	$0.00	$0.05	$1.20	1.0%	0.0%	0.0%	1.0%	16.9%
1,000	$108.48	$102.48	$8.79	$219.75	$110.78	$102.48	$8.89	$222.15	$2.30	$0.00	$0.10	$2.40	1.0%	0.0%	0.0%	1.1%	8.1%
1,500	$155.85	$153.72	$12.90	$322.47	$159.30	$153.72	$13.04	$326.06	$3.45	$0.00	$0.14	$3.59	1.1%	0.0%	0.0%	1.1%	5.0%
2,000	$203.21	$204.96	$17.01	$425.18	$207.81	$204.96	$17.20	$429.97	$4.60	$0.00	$0.19	$4.79	1.1%	0.0%	0.0%	1.1%	13.6%

		Rates Effective October 1, 2019 (o)	Proposed Rates effective April 1, 2020 (p)	Line Item on Bill
(1)	Distribution Customer Charge	$10.00	$10.00	Customer Charge
(2)	LIHEAP Enhancement Charge	$0.80	$0.80	LIHEAP Enhancement Charge
(3)	Renewable Energy Growth Program Charge	$2.95	$2.95	RE Growth Program
(4)	Distribution Charge (per kWh)	$0.04400	$0.04400	
(5)	Operating & Maintenance Expense Charge	$0.00209	$\boxed{\$0.00212}$	
(6)	Operating & Maintenance Expense Reconciliation Factor	($0.00008)	($0.00008)	
(7)	FY21 CapEx Factor Charge	$0.00101	$\boxed{\$0.00328}$	
(8)	CapEx Reconciliation Factor	$0.00074	$0.00074	Distribution Energy Charge
(9)	Revenue Decoupling Adjustment Factor	($0.00061)	($0.00061)	
(10)	Pension Adjustment Factor	($0.00005)	($0.00005)	
(11)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(12)	Arrearage Management Adjustment Factor	$0.00010	$0.00010	
(13)	Low Income Discount Recovery Factor	$0.00152	$0.00152	
(14)	Long-term Contracting for Renewable Energy Charge	$0.00711	$0.00711	Renewable Energy Distribution Charge
(15)	Net Metering Charge	$0.00068	$0.00068	
(16)	Base Transmission Charge	$0.03047	$0.03047	
(17)	Transmission Adjustment Factor	($0.00582)	($0.00582)	Transmission Charge
(18)	Transmission Uncollectible Factor	$0.00032	$0.00032	
(19)	Base Transition Charge	($0.00093)	($0.00093)	Transition Charge
(20)	Transition Adjustment	($0.00021)	($0.00021)	
(21)	Energy Efficiency Program Charge	$0.01151	$0.01151	Energy Efficiency Programs
(22)	Standard Offer Service Base Charge	$0.09814	$0.09814	
(23)	SOS Adjustment Factor	$0.00154	$0.00154	Supply Services Energy Charge
(24)	SOS Adminstrative Cost Adjustment Factor	$0.00217	$0.00217	
(25)	Renewable Energy Standard Charge	$0.00063	$0.00063	
	Line Item on Bill			
(26)	Customer Charge	$10.00	$10.00	
(27)	LIHEAP Enhancement Charge	$0.80	$0.80	
(28)	RE Growth Program	$2.95	$2.95	
(29)	Transmission Charge	$0.02497	$0.02497	
(30)	Distribution Energy Charge	$0.05160	$\boxed{\$0.05390}$	
(31)	Transition Charge	($0.00114)	($0.00114)	
(32)	Energy Efficiency Programs	$0.01151	$0.01151	
(33)	Renewable Energy Distribution Charge	$0.00779	$0.00779	
(34)	Supply Services Energy Charge	$0.10248	$0.10248	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2019, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2019
Column (p): Line (5) per Section 6, Page 1, Line (1), Column (b); Line (7) per Section 6, Page 1, Line (3), Column (b)

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, 2019				Proposed Rates effective April 1, 2020				$ 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	$474.27	$409.92	$36.84	$921.03	$481.49	$409.92	$37.14	$928.55	$7.22	$0.00	$0.30	$7.52	0.8%	0.0%	0.0%	0.8%
50	200	10,000	$1,030.35	$1,024.80	$85.63	$2,140.78	$1,058.45	$1,024.80	$86.80	$2,170.05	$28.10	$0.00	$1.17	$29.27	1.3%	0.0%	0.1%	1.4%
100	200	20,000	$1,957.15	$2,049.60	$166.95	$4,173.70	$2,020.05	$2,049.60	$169.57	$4,239.22	$62.90	$0.00	$2.62	$65.52	1.5%	0.0%	0.1%	1.6%
150	200	30,000	$2,883.95	$3,074.40	$248.26	$6,206.61	$2,981.65	$3,074.40	$252.34	$6,308.39	$97.70	$0.00	$4.08	$101.78	1.6%	0.0%	0.1%	1.6%
20	300	6,000	$545.73	$614.88	$48.36	$1,208.97	$553.21	$614.88	$48.67	$1,216.76	$7.48	$0.00	$0.31	$7.79	0.6%	0.0%	0.0%	0.6%
50	300	15,000	$1,209.00	$1,537.20	$114.43	$2,860.63	$1,237.75	$1,537.20	$115.62	$2,890.57	$28.75	$0.00	$1.19	$29.94	1.0%	0.0%	0.0%	1.0%
100	300	30,000	$2,314.45	$3,074.40	$224.54	$5,613.39	$2,378.65	$3,074.40	$227.21	$5,680.26	$64.20	$0.00	$2.67	$66.87	1.1%	0.0%	0.0%	1.2%
150	300	45,000	$3,419.90	$4,611.60	$334.65	$8,366.15	$3,519.55	$4,611.60	$338.80	$8,469.95	$99.65	$0.00	$4.15	$103.80	1.2%	0.0%	0.0%	1.2%
20	400	8,000	$617.19	$819.84	$59.88	$1,496.91	$624.93	$819.84	$60.20	$1,504.97	$7.74	$0.00	$0.32	$8.06	0.5%	0.0%	0.0%	0.5%
50	400	20,000	$1,387.65	$2,049.60	$143.22	$3,580.47	$1,417.05	$2,049.60	$144.44	$3,611.09	$29.40	$0.00	$1.22	$30.62	0.8%	0.0%	0.0%	0.9%
100	400	40,000	$2,671.75	$4,099.20	$282.12	$7,053.07	$2,737.25	$4,099.20	$284.85	$7,121.30	$65.50	$0.00	$2.73	$68.23	0.9%	0.0%	0.0%	1.0%
150	400	60,000	$3,955.85	$6,148.80	$421.03	$10,525.68	$4,057.45	$6,148.80	$425.26	$10,631.51	$101.60	$0.00	$4.23	$105.83	1.0%	0.0%	0.0%	1.0%
20	500	10,000	$688.65	$1,024.80	$71.39	$1,784.84	$696.65	$1,024.80	$71.73	$1,793.18	$8.00	$0.00	$0.34	$8.34	0.4%	0.0%	0.0%	0.5%
50	500	25,000	$1,566.30	$2,562.00	$172.01	$4,300.31	$1,596.35	$2,562.00	$173.26	$4,331.61	$30.05	$0.00	$1.25	$31.30	0.7%	0.0%	0.0%	0.7%
100	500	50,000	$3,029.05	$5,124.00	$339.71	$8,492.76	$3,095.85	$5,124.00	$342.49	$8,562.34	$66.80	$0.00	$2.78	$69.58	0.8%	0.0%	0.0%	0.8%
150	500	75,000	$4,491.80	$7,686.00	$507.41	$12,685.21	$4,595.35	$7,686.00	$511.72	$12,793.07	$103.55	$0.00	$4.31	$107.86	0.8%	0.0%	0.0%	0.9%
20	600	12,000	$760.11	$1,229.76	$82.91	$2,072.78	$768.37	$1,229.76	$83.26	$2,081.39	$8.26	$0.00	$0.35	$8.61	0.4%	0.0%	0.0%	0.4%
50	600	30,000	$1,744.95	$3,074.40	$200.81	$5,020.16	$1,775.65	$3,074.40	$202.09	$5,052.14	$30.70	$0.00	$1.28	$31.98	0.6%	0.0%	0.0%	0.6%
100	600	60,000	$3,386.35	$6,148.80	$397.30	$9,932.45	$3,454.45	$6,148.80	$400.14	$10,003.39	$68.10	$0.00	$2.84	$70.94	0.7%	0.0%	0.0%	0.7%
150	600	90,000	$5,027.75	$9,223.20	$593.79	$14,844.74	$5,133.25	$9,223.20	$598.19	$14,954.64	$105.50	$0.00	$4.40	$109.90	0.7%	0.0%	0.0%	0.7%

		Rates Effective October 1, 2019 (o)	Proposed Rates effective April 1, 2020 (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	$27.95	$27.95	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 10kW)	$6.75	$6.75	Distribution Demand Charge
(5)	FY21 CapEx Factor Demand Charge (per kW > 10kW)	$0.27	$0.94	
(6)	Distribution Charge (per kWh)	$0.00465	$0.00465	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00156	$0.00169	
(8)	Operating & Maintenance Expense Reconciliation Factor	($0.00008)	($0.00008)	
(9)	CapEx Reconciliation Factor	$0.00058	$0.00058	
(10)	Revenue Decoupling Adjustment Factor	($0.00061)	($0.00061)	
(11)	Pension Adjustment Factor	($0.00005)	($0.00005)	
(12)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13)	Arrearage Management Adjustment Factor	$0.00010	$0.00010	
(14)	Low Income Discount Recovery Factor	$0.00152	$0.00152	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00711	$0.00711	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00068	$0.00068	
(17)	Transmission Demand Charge	$4.37	$4.37	Transmission Demand Charge
(18)	Base Transmission Charge	$0.01154	$0.01154	Transmission Adjustment
(19)	Transmission Adjustment Factor	($0.00481)	($0.00481)	
(20)	Transmission Uncollectible Factor	$0.00029	$0.00029	
(21)	Base Transition Charge	($0.00093)	($0.00093)	Transition Charge
(22)	Transition Adjustment	($0.00021)	($0.00021)	
(23)	Energy Efficiency Program Charge	$0.01151	$0.01151	Energy Efficiency Programs
(24)	Standard Offer Service Base Charge	$0.09814	$0.09814	Supply Services Energy Charge
(25)	SOS Adjustment Factor	$0.00154	$0.00154	
(26)	SOS Adminstrative Cost Adjustment Factor	$0.00217	$0.00217	
(27)	Renewable Energy Standard Charge	$0.00063	$0.00063	
	Line Item on Bill			
(28)	Customer Charge	$145.00	$145.00	
(30)	LIHEAP Enhancement Charge	$0.80	$0.80	
(29)	RE Growth Program	$27.95	$27.95	
(31)	Transmission Adjustment	$0.00702	$0.00702	
(32)	Distribution Energy Charge	$0.01055	$0.01068	
(33)	Distribution Demand Charge	$7.02	$7.69	
(34)	Transmission Demand Charge	$4.37	$4.37	
(33)	Transition Charge	($0.00114)	($0.00114)	
(34)	Energy Efficiency Programs	$0.01151	$0.01151	
(35)	Renewable Energy Distribution Charge	$0.00779	$0.00779	
(36)	Supply Services Energy Charge	$0.10248	$0.10248	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2019, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2019
Column (p): Line (5) per Section 6, Page 1, Line (4), Column (c); Line (7) per Section 6, Page 1, Line (1), Column (c)

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, 2019				Proposed Rates effective April 1, 2020				$ 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	$3,693.31	$3,508.40	$300.07	$7,501.78	$3,696.11	$3,508.40	$300.19	$7,504.70	$2.80	$0.00	$0.12	$2.92	0.0%	0.0%	0.0%	0.0%
750	200	150,000	$13,187.41	$13,156.50	$1,097.66	$27,441.57	$13,555.41	$13,156.50	$1,113.00	$27,824.91	$368.00	$0.00	$15.34	$383.34	1.3%	0.0%	0.1%	1.4%
1,000	200	200,000	$17,502.91	$17,542.00	$1,460.20	$36,505.11	$18,036.91	$17,542.00	$1,482.45	$37,061.36	$534.00	$0.00	$22.25	$556.25	1.5%	0.0%	0.1%	1.5%
1,500	200	300,000	$26,133.91	$26,313.00	$2,185.29	$54,632.20	$26,999.91	$26,313.00	$2,221.37	$55,534.28	$866.00	$0.00	$36.08	$902.08	1.6%	0.0%	0.1%	1.7%
2,500	200	500,000	$43,395.91	$43,855.00	$3,635.45	$90,886.36	$44,925.91	$43,855.00	$3,699.20	$92,480.11	$1,530.00	$0.00	$63.75	$1,593.75	1.7%	0.0%	0.1%	1.8%
5,000	200	1,000,000	$86,550.91	$87,710.00	$7,260.87	$181,521.78	$89,740.91	$87,710.00	$7,393.79	$184,844.70	$3,190.00	$0.00	$132.92	$3,322.92	1.8%	0.0%	0.1%	1.8%
7,500	200	1,500,000	$129,705.91	$131,565.00	$10,886.29	$272,157.20	$134,555.91	$131,565.00	$11,088.37	$277,209.28	$4,850.00	$0.00	$202.08	$5,052.08	1.8%	0.0%	0.1%	1.9%
10,000	200	2,000,000	$172,860.91	$175,420.00	$14,511.71	$362,792.62	$179,370.91	$175,420.00	$14,782.96	$369,573.87	$6,510.00	$0.00	$271.25	$6,781.25	1.8%	0.0%	0.1%	1.9%
20,000	200	4,000,000	$345,480.91	$350,840.00	$29,013.37	$725,334.28	$358,630.91	$350,840.00	$29,561.29	$739,032.20	$13,150.00	$0.00	$547.92	$13,697.92	1.8%	0.0%	0.1%	1.9%
200	300	60,000	$4,426.51	$5,262.60	$403.71	$10,092.82	$4,430.71	$5,262.60	$403.89	$10,097.20	$4.20	$0.00	$0.18	$4.38	0.0%	0.0%	0.0%	0.0%
750	300	225,000	$15,936.91	$19,734.75	$1,486.32	$37,157.98	$16,310.16	$19,734.75	$1,501.87	$37,546.78	$373.25	$0.00	$15.55	$388.80	1.0%	0.0%	0.0%	1.0%
1,000	300	300,000	$21,168.91	$26,313.00	$1,978.41	$49,460.32	$21,709.91	$26,313.00	$2,000.95	$50,023.86	$541.00	$0.00	$22.54	$563.54	1.1%	0.0%	0.0%	1.1%
1,500	300	450,000	$31,632.91	$39,469.50	$2,962.60	$74,065.01	$32,509.41	$39,469.50	$2,999.12	$74,978.03	$876.50	$0.00	$36.52	$913.02	1.2%	0.0%	0.0%	1.2%
2,500	300	750,000	$52,560.91	$65,782.50	$4,930.98	$123,274.39	$54,108.41	$65,782.50	$4,995.45	$124,886.36	$1,547.50	$0.00	$64.47	$1,611.97	1.3%	0.0%	0.1%	1.3%
5,000	300	1,500,000	$104,880.91	$131,565.00	$9,851.91	$246,297.82	$108,105.91	$131,565.00	$9,986.29	$249,657.20	$3,225.00	$0.00	$134.38	$3,359.38	1.3%	0.0%	0.1%	1.4%
7,500	300	2,250,000	$157,200.91	$197,347.50	$14,772.85	$369,321.26	$162,103.41	$197,347.50	$14,977.12	$374,428.03	$4,902.50	$0.00	$204.27	$5,106.77	1.3%	0.0%	0.1%	1.4%
10,000	300	3,000,000	$209,520.91	$263,130.00	$19,693.79	$492,344.70	$216,100.91	$263,130.00	$19,967.96	$499,198.87	$6,580.00	$0.00	$274.17	$6,854.17	1.3%	0.0%	0.1%	1.4%
20,000	300	6,000,000	$418,800.91	$526,260.00	$39,377.54	$984,438.45	$432,090.91	$526,260.00	$39,931.29	$998,282.20	$13,290.00	$0.00	$553.75	$13,843.75	1.4%	0.0%	0.1%	1.4%
200	400	80,000	$5,159.71	$7,016.80	$507.35	$12,683.86	$5,165.31	$7,016.80	$507.59	$12,689.70	$5.60	$0.00	$0.24	$5.84	0.0%	0.0%	0.0%	0.0%
750	400	300,000	$18,686.41	$26,313.00	$1,874.98	$46,874.39	$19,064.91	$26,313.00	$1,890.75	$47,268.66	$378.50	$0.00	$15.77	$394.27	0.8%	0.0%	0.0%	0.8%
1,000	400	400,000	$24,834.91	$35,084.00	$2,496.62	$62,415.53	$25,382.91	$35,084.00	$2,519.45	$62,986.36	$548.00	$0.00	$22.83	$570.83	0.9%	0.0%	0.0%	0.9%
1,500	400	600,000	$37,131.91	$52,626.00	$3,739.91	$93,497.82	$38,018.91	$52,626.00	$3,776.87	$94,421.78	$887.00	$0.00	$36.96	$923.96	0.9%	0.0%	0.0%	1.0%
2,500	400	1,000,000	$61,725.91	$87,710.00	$6,226.50	$155,662.41	$63,290.91	$87,710.00	$6,291.71	$157,292.62	$1,565.00	$0.00	$65.21	$1,630.21	1.0%	0.0%	0.0%	1.0%
5,000	400	2,000,000	$123,210.91	$175,420.00	$12,442.96	$311,073.87	$126,470.91	$175,420.00	$12,578.79	$314,469.70	$3,260.00	$0.00	$135.83	$3,395.83	1.0%	0.0%	0.0%	1.1%
7,500	400	3,000,000	$184,695.91	$263,130.00	$18,659.41	$466,485.32	$189,650.91	$263,130.00	$18,865.87	$471,646.78	$4,955.00	$0.00	$206.46	$5,161.46	1.1%	0.0%	0.0%	1.1%
10,000	400	4,000,000	$246,180.91	$350,840.00	$24,875.87	$621,896.78	$252,830.91	$350,840.00	$25,152.96	$628,823.87	$6,650.00	$0.00	$277.09	$6,927.09	1.1%	0.0%	0.0%	1.1%
20,000	400	8,000,000	$492,120.91	$701,680.00	$49,741.71	$1,243,542.62	$505,550.91	$701,680.00	$50,301.29	$1,257,532.20	$13,430.00	$0.00	$559.58	$13,989.58	1.1%	0.0%	0.0%	1.1%
200	500	100,000	$5,892.91	$8,771.00	$611.00	$15,274.91	$5,899.91	$8,771.00	$611.29	$15,282.20	$7.00	$0.00	$0.29	$7.29	0.0%	0.0%	0.0%	0.0%
750	500	375,000	$21,435.91	$32,891.25	$2,263.63	$56,590.79	$21,819.66	$32,891.25	$2,279.62	$56,990.53	$383.75	$0.00	$15.99	$399.74	0.7%	0.0%	0.0%	0.7%
1,000	500	500,000	$28,500.91	$43,855.00	$3,014.83	$75,370.74	$29,055.91	$43,855.00	$3,037.95	$75,948.86	$555.00	$0.00	$23.12	$578.12	0.7%	0.0%	0.0%	0.8%
1,500	500	750,000	$42,630.91	$65,782.50	$4,517.23	$112,930.64	$43,528.41	$65,782.50	$4,554.62	$113,865.53	$897.50	$0.00	$37.39	$934.89	0.8%	0.0%	0.0%	0.8%
2,500	500	1,250,000	$70,890.91	$109,637.50	$7,522.02	$188,050.43	$72,473.41	$109,637.50	$7,587.96	$189,698.87	$1,582.50	$0.00	$65.94	$1,648.44	0.8%	0.0%	0.0%	0.9%
5,000	500	2,500,000	$141,540.91	$219,275.00	$15,034.00	$375,849.91	$144,835.91	$219,275.00	$15,171.29	$379,282.20	$3,295.00	$0.00	$137.29	$3,432.29	0.9%	0.0%	0.0%	0.9%
7,500	500	3,750,000	$212,190.91	$328,912.50	$22,545.98	$563,649.39	$217,198.41	$328,912.50	$22,754.62	$568,865.53	$5,007.50	$0.00	$208.64	$5,216.14	0.9%	0.0%	0.0%	0.9%
10,000	500	5,000,000	$282,840.91	$438,550.00	$30,057.96	$751,448.87	$289,560.91	$438,550.00	$30,337.96	$758,448.87	$6,720.00	$0.00	$280.00	$7,000.00	0.9%	0.0%	0.0%	0.9%
20,000	500	10,000,000	$565,440.91	$877,100.00	$60,105.88	$1,502,646.79	$579,010.91	$877,100.00	$60,671.29	$1,516,782.20	$13,570.00	$0.00	$565.41	$14,135.41	0.9%	0.0%	0.0%	0.9%
200	600	120,000	$6,626.11	$10,525.20	$714.64	$17,865.95	$6,634.51	$10,525.20	$714.99	$17,874.70	$8.40	$0.00	$0.35	$8.75	0.0%	0.0%	0.0%	0.0%
750	600	450,000	$24,185.41	$39,469.50	$2,652.29	$66,307.20	$24,574.41	$39,469.50	$2,668.50	$66,712.41	$389.00	$0.00	$16.21	$405.21	0.6%	0.0%	0.0%	0.6%
1,000	600	600,000	$32,166.91	$52,626.00	$3,533.04	$88,325.95	$32,728.91	$52,626.00	$3,556.45	$88,911.36	$562.00	$0.00	$23.41	$585.41	0.6%	0.0%	0.0%	0.7%
1,500	600	900,000	$48,129.91	$78,939.00	$5,294.54	$132,363.45	$49,037.91	$78,939.00	$5,332.37	$133,309.28	$908.00	$0.00	$37.83	$945.83	0.7%	0.0%	0.0%	0.7%
2,500	600	1,500,000	$80,055.91	$131,565.00	$8,817.54	$220,438.45	$81,655.91	$131,565.00	$8,884.21	$222,105.12	$1,600.00	$0.00	$66.67	$1,666.67	0.7%	0.0%	0.0%	0.8%
5,000	600	3,000,000	$159,870.91	$263,130.00	$17,625.04	$440,625.95	$163,200.91	$263,130.00	$17,763.79	$444,094.70	$3,330.00	$0.00	$138.75	$3,468.75	0.8%	0.0%	0.0%	0.8%
7,500	600	4,500,000	$239,685.91	$394,695.00	$26,432.54	$660,813.45	$244,745.91	$394,695.00	$26,643.37	$666,084.28	$5,060.00	$0.00	$210.83	$5,270.83	0.8%	0.0%	0.0%	0.8%
10,000	600	6,000,000	$319,500.91	$526,260.00	$35,240.04	$881,000.95	$326,290.91	$526,260.00	$35,522.96	$888,073.87	$6,790.00	$0.00	$282.92	$7,072.92	0.8%	0.0%	0.0%	0.8%
20,000	600	12,000,000	$638,760.91	$1,052,520.00	$70,470.04	$1,761,750.95	$652,470.91	$1,052,520.00	$71,041.29	$1,776,032.20	$13,710.00	$0.00	$571.25	$14,281.25	0.8%	0.0%	0.0%	0.8%

		Rates Effective October 1, 2019 (o)	Proposed Rates effective April 1, 2020 (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	$232.11	$232.11	RE Growth Program
(4)	Base Distribution Demand Charge (per kW > 200kW)	$5.20	$5.20	Distribution Demand Charge
(5)	FY21 CapEx Factor Demand Charge (per kW > 200kW)	$0.26	$0.91	
(6)	Distribution Charge (per kWh)	$0.00418	$0.00418	Distribution Energy Charge
(7)	Operating & Maintenance Expense Charge	$0.00079	$0.00086	
(8)	Operating & Maintenance Expense Reconciliation Factor	($0.00008)	($0.00008)	
(9)	CapEx Reconciliation Factor	$0.00027	$0.00027	
(10)	Revenue Decoupling Adjustment Factor	($0.00061)	($0.00061)	
(11)	Pension Adjustment Factor	($0.00005)	($0.00005)	
(12)	Storm Fund Replenishment Factor	$0.00288	$0.00288	
(13)	Arrearage Management Adjustment Factor	$0.00010	$0.00010	
(14)	Low Income Discount Recovery Factor	$0.00152	$0.00152	
(15)	Long-term Contracting for Renewable Energy Charge	$0.00711	$0.00711	Renewable Energy Distribution Charge
(16)	Net Metering Charge	$0.00068	$0.00068	
(17)	Transmission Demand Charge	$4.47	$4.47	Transmission Demand Charge
(18)	Base Transmission Charge	$0.01166	$0.01166	Transmission Adjustment
(19)	Transmission Adjustment Factor	($0.00245)	($0.00245)	
(20)	Transmission Uncollectible Factor	$0.00029	$0.00029	
(21)	Base Transition Charge	($0.00093)	($0.00093)	Transition Charge
(22)	Transition Adjustment	($0.00021)	($0.00021)	
(23)	Energy Efficiency Program Charge	$0.01151	$0.01151	Energy Efficiency Programs
(24)	Standard Offer Service Base Charge	$0.08337	$0.08337	Supply Services Energy Charge
(25)	SOS Adjustment Factor	$0.00138	$0.00138	
(26)	SOS Adminstrative Cost Adjustment Factor	$0.00233	$0.00233	
(27)	Renewable Energy Standard Charge	$0.00063	$0.00063	
	Line Item on Bill			
(28)	Customer Charge	$1,100.00	$1,100.00	
(29)	LIHEAP Enhancement Charge	$0.80	$0.80	
(30)	RE Growth Program	$232.11	$232.11	
(31)	Transmission Adjustment	$0.00950	$0.00950	
(32)	Distribution Energy Charge	$0.00900	$0.00907	
(33)	Distribution Demand Charge	$5.46	$6.11	
(34)	Transmission Demand Charge	$4.47	$4.47	
(33)	Transition Charge	($0.00114)	($0.00114)	
(34)	Energy Efficiency Programs	$0.01151	$0.01151	
(35)	Renewable Energy Distribution Charge	$0.00779	$0.00779	
(36)	Supply Services Energy Charge	$0.08771	$0.08771	

Column (o): per Summary of Retail Delivery Service Rates, R.I.P.U.C. No. 2095 effective 10/1/2019, and Summary of Rates Standard Offer Service tariff, R.I.P.U.C. No. 2096, effective 10/1/2019
Column (p): Line (5) per Section 6, Page 1, Line (4), Column (e); Line (7) per Section 6, Page 1, Line (1), Column (e)

Testimony of
Melissa A. Little

PRE-FILED DIRECT TESTIMONY

OF

MELISSA A. LITTLE

December 20, 2019

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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 (PUC)?

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 Electric, in the Fiscal Year (FY) 2018 Electric Infrastructure, Safety, and Reliability (ISR) Plan and reconciliation filing in Docket No. 4682, FY 2019 ISR reconciliation filing in Docket No. 4783, and the Electric ISR Plan filing for FY 2020 in Docket No. 4915; and (3) for Narragansett Gas, in the Gas ISR Plan and reconciliation filings for FY 2016 in Docket No. 4540, FY 2017 in Docket No. 4590, FY 2018 in Docket No. 4678, and FY 2019 in Docket No. 4781, and the Gas ISR Plan filing for FY 2020 in Docket No. 4916.

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 2021 Electric ISR Plan (the Electric ISR Plan or Plan), which describes the calculation of the Company's revenue requirement for FY 2021 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. Kathy Castro.

III. <u>ISR PLAN REVENUE REQUIREMENT</u>

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 $32,302,821 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 2021 Property Tax Recovery Adjustment. Lines 1, 2 and 3 of Column (b) reflect the forecasted FY 2021 revenue requirement related to O&M expenses for VM, I&M, and Other Programs of $10,600,000, $1,035,000, and $456,633 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 PUC in Docket No. 4237. Contact Voltage Program costs are included in the $1,035,000 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 2022 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, with the exception of the bonus depreciation assumptions used to calculate tax depreciation on FY 2019 and FY 2020 capital investment. As stated in Section 5 of the Plan, the Company's original interpretation of the Tax Cut and Jobs Act of 2017 (2017 Tax Act) was that no federal tax deduction for bonus depreciation would be allowed in FY 2019 and FY 2020. However, based on current industry practice, the Company has revised its estimate of FY 2019 and FY 2020 bonus depreciation. The Company's FY 2021 revenue requirement includes the impact of the 2017 Tax Act on vintage FY 2018 through FY 2021 capital investment.

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 2019 federal income tax return in December 2019, coincident with the submission of this filing. The Company will compare the results of the actual FY 2019 federal tax return with the tax assumptions used to calculate deferred federal income taxes included in rate base in the FY 2019, FY 2020 and FY 2021 vintage revenue requirement calculations and assess any impact to the Electric ISR Plan revenue requirement. The Company will then file a revised FY 2021 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. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Testimony of
Adam S. Crary

PRE-FILED DIRECT TESTIMONY

OF

ADAM S. CRARY

December 20, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Adam S. Crary, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am a Senior Analyst for Electric Pricing, New England in the Strategy and Regulation Department of National Grid USA Service Company, Inc. 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. In 1995, I graduated from Berklee College of Music in Boston, MA with a Bachelor of Music degree.

Q. Please describe your professional experience?

A For approximately eight years, between 2000 and 2014, I was employed by Computer Sciences Corporation as a Pricing Analyst for their Managed Hosting and Cloud Computing business divisions, respectively. I began my employment as a Senior Pricing Analyst with National Grid in June 2014.

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

A. Yes.

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) 2021 revenue requirement on cumulative actual and forecasted incremental capital investment through March 31, 2021 and FY 2021 operation and maintenance (O&M) expense resulting from the Company's FY 2021 Infrastructure, Safety, and Reliability (ISR) Plan proposed in this filing and to provide the customer bill impacts of the proposed rate changes.

II. INFRASTRUCTURE, SAFETY, AND RELIABILITY PROVISION

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 PUC.

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 PUC approval.

Q. How are the CapEx Factors designed?

A. First, the cumulative revenue requirement approved by the PUC, 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 PUC 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 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&M 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 PUC 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 PUC 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 2021. The revenue requirement of $20,211,188[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 units for the period April 1, 2020 through March 31, 2021. 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 2021. As developed in the testimony of Melissa A. Little, these expenses total

[1] See Section 5: Attachment 1, Page 1, Line 12, Column (b).

$12,091,633.[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.

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. For a residential customer receiving Standard Offer Service and using 500 kWh per month, implementation of the proposed ISR factors will result in a monthly bill increase of $1.43, or 1.2%.

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

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

annual Electric Retail Rate filing in February 2020 and will propose additional rate changes for effect April 1, 2020. Therefore, the Company will submit a compliance filing following the PUC'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, 2020.

VI. <u>DOCKET 4600</u>

Q. Did the Company apply the Docket 4600 principles of rate design to the FY 2021 Electric ISR Plan?

A. The Company did not perform a specific analysis of the rate design principles in the context of the proposed FY 2021 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 PUC 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 2021 Electric ISR Plan.

VI. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes, it does.