The Narragansett Electric Company
d/b/a National Grid

Grid Modernization Plan

Testimony and Attachments of:
Stephen Lasher

January 21, 2021

RIPUC Docket No. 5114

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

January 21, 2021

VIA HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket No. 5114 - The Narragansett Electric Company d/b/a National Grid <u>Grid Modernization Plan</u>

Dear Ms. Massaro:

Enclosed for filing with the Public Utilities Commission (PUC) is an original and ten copies of the Company's[1] Grid Modernization Plan (GMP) pursuant to Article II, Section C.15.b of the Amended Settlement Agreement (ASA) approved by the PUC at its Open Meeting on August 24, 2018 in Docket Nos. 4770 & 4780.[2]

The Company's filing consists of a detailed proposal to implement its Rhode Island GMP. The GMP, which is being filed concurrently with the Company's Updated Advanced Metering Functionality (AMF) Business Case, is an informational guidance document that presents a holistic plan of activities and investments expected to be necessary to manage the electric distribution grid more granularly considering a range of Distributed Energy Resource (DER) adoption levels through 2030. Specifically, the GMP includes a five-year implementation plan, a ten-year roadmap, and a comprehensive benefit-cost analysis (BCA), which the Company developed consistent with the PUC's Benefit-Cost Framework adopted in Docket 4600.[3] Through this filing, the Company is requesting PUC approval of the GMP and BCA for the purpose of allowing the Company to present future grid modernization investment proposals, consistent with the approved GMP, for cost-recovery in the Company's Infrastructure, Safety and Reliability Plan filings and/or general rate case proceedings.

Grid modernization does not refer to a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably. To that end, the Company's GMP presents a coordinated and integrated plan to address three key unmet needs in Rhode Island: (1) operational needs, by enabling cost-effective solutions for distribution system issues caused by customer DER adoption; (2) customer needs by providing

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

[2] *See* Docket Nos. 4770 & 4780, Report and Order No. 23823 (May 5, 2020).

[3] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates In Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 (July 31, 2017).

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them with more energy savings opportunities, clean energy options, simpler and lower-cost DER interconnections, reliability improvements, and greater choice and control in addressing their energy needs compared to a future without grid modernization; and (3) taking further steps to achieve clean energy goals.

The Company has undertaken a thoughtful and thorough approach to developing the GMP. This process, which spanned approximately two years, included engagement with stakeholders through the AMF/GMP Subcommittee of the Power Sector Transformation Advisory Group, as well as other targeted deep-dive sessions with the Division of Public Utilities and Carriers and the Office of Energy Resources, and a workshop and two additional technical sessions with the PUC. The GMP expands significantly on the initial grid modernization plans filed with the Company's Power Sector Transformation Vision and Implementation Plan in Docket No. 4780, including addressing feedback from stakeholders and the PUC. Table 1.1 of the GMP details how the GMP addresses each of the relevant grid modernization requirements within the ASA.

In support of the Company's GMP, this filing includes the pre-filed direct testimony and attachments of Stephen Lasher. Schedule SL-1 contains the GMP Business Case. Also enclosed are the GMP Implementation Plan (Attachment A), the Appendix (Attachment B), and the confidential BCA (Attachment C), provided as an Excel file.

This filing also includes a Motion for Protective Treatment in accordance with Rule 1.3(H)(3) of the PUC Rules of Practice and Procedure, 810-RICR-00-00-1-1.3(H)(3) (Rule 1.3(H)), and R.I. Gen. Laws § 38-2-2(4)(B). The Company seeks protection from public disclosure of the confidential BCA in Attachment C. Due to the size and voluminous nature of the Excel file, the Company is providing the PUC with the confidential Excel file via the PUC's secure website and marked as **"Contains Privileged and Confidential Information – Do Not Release."** Accordingly, the Company has not included redacted copies of this material for the public filing.

Thank you very much for your time and attention to this matter. If you have any questions, please contact Jennifer Brooks Hutchinson at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Jennifer Brooks Hutchinson

Enclosures

cc: John Bell, Division
Leo Wold, Esq.

STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Grid Modernization Plan	)	Docket No. 5114

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

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

I. BACKGROUND

On January 21, 2021, National Grid submitted its Grid Modernization Plan (GMP) Business Case in the above-captioned docket. In that filing, the Company filed its BCA Model in Excel format as Attachment C to the Pre-Filed Direct Testimony of Stephen Lasher (the BCA Model). The BCA Model contains confidential and proprietary commercial and financial information that the Company ordinarily would not share with the public.

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

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the BCA Model.

II. LEGAL STANDARD

Rule 1.3(H) 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.* APRA establishes the balance between "public access to public records" and protection "from disclosure [of] information about particular individuals maintained in the files of public bodies when disclosure would constitute an unwarranted invasion of personal privacy." Gen. Laws § 38-2-1. Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency are deemed "public records" unless the information contained in such documents and materials falls within one of the exceptions specifically identified in Gen. Laws § 38-2-2(4). *See id.* § 38-2-3. 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.

APRA 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 that is of a privileged or confidential nature.

Id. § 38-2-2(4)(B).

The Rhode Island Supreme Court has held that when documents fall within a specific APRA exemption, they "are not considered to be public records," and "the act does not apply to them." *Providence Journal Co. v. Kane*, 577 A.2d 661, 663 (R.I. 1990). Further, the court has held that "financial or commercial information" under APRA includes information "whose disclosure 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 position of the person from whom the information was obtained." *Providence Journal Co. v. Convention Ctr. Auth.*, 774 A.2d 40, 47 (R.I. 2001) (internal quotation marks omitted). 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. *Id.* at 47.

III. BASIS FOR CONFIDENTIALITY

The BCA Model contains confidential and proprietary commercial and financial information relating to the Company's business operations. The Company ordinarily does not make it available to the public. The Company has provided it on a voluntary basis to assist the PUC with its decision-making in this proceeding. Therefore, this information satisfies the APRA exception found in Gen. Laws § 38-2-2(4)(B).

The BCA Model constitutes "commercial or financial information" to which the APRA public disclosure requirements do not apply. *See* Gen. Laws § 38-2-2(4)(B); *Kane*, 577 A.2d at 663. The Company therefore respectfully requests that the PUC grant protective treatment to the BCA Model and take the following actions to preserve its confidentiality: (1) maintain the BCA Model as confidential indefinitely; (2) not place the BCA Model on the public docket; and (3) disclose BCA Model only to the PUC, its attorneys, and staff as necessary to review this docket.

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: January 21, 2021

PRE-FILED TESTIMONY

OF

STEPHEN LASHER

Table of Contents

I. **<u>Introduction</u>**

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

A. My name is Stephen Lasher. My business address is 447 Dexter Street, Providence, Rhode Island 02907.

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

A. I am employed by National Grid USA Service Company, Inc. (Service Company) and currently hold the position of Principal Engineer in the Grid Modernization Solutions Group under the US Electric Business Unit. My responsibilities include supporting The Narragansett Electric Company d/b/a National Grid's (the Company) transition to a modern electric grid through identification and evaluation of potential next opportunities, technologies, or processes to provide measurable value to customers in Rhode Island.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Cincinnati with a Bachelor of Science Degree in Civil and Environmental Engineering in 1997 and from the Massachusetts Institute of Technology with a Master of Science Degree in Mechanical Engineering in 1999.

I joined National Grid in 2016 as a Principal Engineer in the Advanced Grid Engineering Group under the New Energy Solutions Business Unit, and later I joined the Grid Modernization Solutions group under the Electric Business Unit. My responsibilities have included the following: technical lead for Niagara Mohawk Power Corporation's Reforming the Energy Vision Distributed System Platform Demonstration Project in Buffalo, New York; technical lead for National Grid's Non-Wires Alternative (NWA) project deferral calculations; co-author of National Grid's Grid Modernization Strategy Roadmap; and business lead for the Company's Grid Modernization Plan (GMP).

Prior to joining National Grid, I spent nearly two decades working on projects relating to clean and emerging energy technologies, including solar energy, smart grid, energy storage, electric vehicle, and microgrid projects. From 1999 to 2010, I was employed by Arthur D. Little Inc. and later by TIAX LLC, both Cambridge Massachusetts-based consulting and technology development companies, as an Engineer, Program Manager, Group Manager, and Business Development Leader.

From 2010 to 2012, I was employed by Satcon Technology Corporation, a Boston-based solar inverter company, as its Director of Business Development for Research and Development and later as its Director of Product Management for Central Inverters.

From 2012 to 2014, I worked as a consultant to small businesses, providing technical and market insights, driving new product development programs, and helping capture new business and outside funding opportunities for the development and commercialization of emerging energy technologies.

From 2014 to 2015, I was employed by eNow Inc., a Warwick, Rhode Island-based manufacturer of solar power solutions for the transportation sector, as its Vice President of Business Development.

Immediately prior to joining National Grid, from 2015 to 2016, I was employed by Sensata Technologies, Inc., an Attleboro, Massachusetts-based manufacturer of sensors and controls for a broad range of markets and applications, as its North American Market Manager for Performance Sensors.

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

A. Yes, I testified regarding the volt-VAR optimization (VVO) program as part of the fiscal year (FY) 2021 Infrastructure, Safety and Reliability Plan in Docket No. 4995. Also, I presented updates regarding the Company's Grid Modernization Plan (GMP) filing to the PUC at the Power Sector Transformation (PST) Workshop on April 9, 2019 and the PUC Technical Sessions held on November 5, 2019 and September 24, 2020.

II. Purpose and Structure of Testimony

Q. Please describe the purpose of this testimony.

A. The purpose of this testimony is to present the Company's GMP and request that the PUC approve the GMP Business Case and benefit-cost analysis (BCA) for the purpose of allowing the Company to make grid modernization investment proposals in the future.

This testimony addresses the requirements of the Amended Settlement Agreement approved by the PUC at its Open Meeting on August 24, 2018, in Docket No. 4770 (referred to herein as, the ASA). Article II, Section C.15 of the ASA required the Company to file a comprehensive GMP that would provide a full assessment of the various modernization initiatives under consideration by the Company, including an explanation and evaluation of how the initiatives relate to each other. This testimony, the GMP Business Case, and supporting attachments each address this requirement.

Q. How is the testimony structured?

A. Sections I and II are the Introduction, and Purpose and Structure of the Testimony. Section III explains the need for grid modernization today. Section IV provides an overview of the GMP. Section V describes stakeholder engagement and their involvement in the development of the GMP. Section VI discusses the GMP approach and development, and Section VII gives an overview of proposed GMP investments.

Section VIII describes the BCA performed for all the investments envisioned in the GMP, and Section IX concludes the testimony.

Q. Have you included any attachments as part of your testimony?

A. Yes, I am sponsoring the following attachments, which were prepared or compiled under my direction and supervision:

- Schedule SL-1 is the GMP Business Case, which includes the following attachments:
  - Attachment A is the GMP Implementation Plan;
  - Attachment B is the GMP Appendix, which includes technical and planning details that support the GMP Business Case and Implementation Plan; and
  - Attachment C is the GMP BCA Model - **CONFIDENTIAL**

III. Why Rhode Island Needs Grid Modernization Now

Q. Please briefly describe the changes to the energy landscape leading to the need to manage the distribution system with more granularity.

A. Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increasing adoption of distributed energy resources (DERs) such as renewable distributed generation (DG), beneficial electrification, electric vehicles (EVs), electric heat pumps (EHPs), and advanced "smart" technologies to actively manage energy use in customers' homes and places of businesses.[1]

Utilities and stakeholders often reference these trends as a shift from one-way flow of electricity and information, moving from the utility to the customer, to two-way flow of electricity and information. While the "one-way" electric power system has served utility customers well for decades, the new demands on the electric grid from technology advances and increased customer adoption of DERs have created a two-way electric power system that is more dynamic and less predictable. Whereas electricity distribution equipment historically has required only local autonomous control settings, without the need for remote monitoring or real-time controls, the emerging model of two-way flow of information and energy requires the Company to manage the distribution system with more granularity, including more real-time visibility into the distribution system and increased ability to communicate energy usage information to customers.

Q. How does the proliferation of DERs, particularly DG, impact the distribution system?

A. The coincidence of DER injections from renewable generation sources like solar and wind DG does not align well with traditional customer electric loads (i.e., base loads) and

[1] DERs refer to resources sited close to customers that can provide for electricity generation or flexible demand. Examples of electricity generation DERs include solar DG, wind DG, and combined heat and power. Examples of flexible demand DERs include energy storage, EVs, and EHPs.

new consumption demands expected from beneficial electrification solutions like EVs and EHPs. For example, solar DG output typically peaks between 11 a.m. and 1 p.m. in the early spring, while current base load demand peaks between 5 p.m. and 7 p.m. on the hottest days of the summer. Unmanaged load from residential EV charging is also likely to occur between 5 p.m. and 7 p.m. when customers return home from work.

Therefore, future loads from solar and wind DG will continue to reduce minimum load periods (e.g., 11 a.m. until 1 p.m. in the early spring), which can create high-voltage issues on the distribution system; while unmanaged future loads from EV charging will likely increase peak load periods (e.g., 5 p.m. until 7 p.m. in the summer), which can create low-voltage and thermal overload issues on the distribution system. This mismatch between renewable DG injections and peak load periods results in a less efficient load factor, large swings in voltage, and thermal overloads, which results in higher costs to rate payers.

Q. What does the Company mean by "grid modernization"?

A. The Company uses the term "grid modernization" to refer to those investments associated with managing the distribution system with more granularity to create a platform of solutions that enables more DERs to connect, while also giving customers more control over their energy decisions, reducing energy use, and improving reliability. Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving behavior and expectations of customers safely and reliably.

Q. How does the Company interconnect DERs to the distribution system today?

A. There is currently little real-time visibility of the grid downstream of the substation, limiting the Company's ability to monitor loading (i.e., kW) and voltage. Therefore, when DERs are studied for interconnection, to prevent reliability and safety issues for neighboring customers, on the distribution system today, system planners need to use conservative assumptions during the interconnection application phase. This can result in interconnection costs that may be higher than interconnection costs if more granular information was available. In addition, system operators need to use conservative assumptions during the operating phase, which to date, have not reduced DER performance, but as DG saturation continues to grow, could result in the need to reduce a specific DG project's power output.

With the proliferation of DERs comes an increasing complexity in managing core compliance obligations such as system load, voltage, and protection systems that are the key to distribution system safety and reliability. The Company's Distribution Planning and Asset Management (DPAM) engineers analyze the impact of DERs on the distribution system's performance at the commencement of discrete System Impact Study (SIS) agreements. The analyses conducted identify potential concerns due to specific

DER interconnections and system modifications required to maintain compliance. Studies consider all interconnected and proposed DERs within the analysis. System modifications are assigned to the project to make sure the project will not cause reliability or safety issues with neighboring customers.

Modifications range from significant infrastructure upgrades to the suggestion of reducing the size of a planned DER project. As DER adoption expands, more components of the distribution, subtransmission, and the transmission system become impacted. In addition, the distribution system is continuously reconfigured for other reasons (e.g., reliability, thermal, voltage, arc flash performance), so as DG saturation continues to grow, it can become increasingly difficult to assign specific system modifications to any one DER interconnection project.

Likewise, the Company’s Control Center operators analyze the impact of DERs on the distribution system’s performance where monitoring is available. Based on the lack of granular monitoring or real-time load flow, and without localized forecasting, operators make conservative estimates when it comes to DER and their contribution to power aspects of the grid. Today, operators sometimes need to take DERs offline during abnormal events, but in the future, unplanned DER curtailment could be more widespread. As DER levels increase in high DER penetration areas, operators would work with DPAM engineers to curtail DERs on a seasonal basis using conservative assumptions to ensure voltage and thermal overloads are not possible under "worst case" scenarios. For example, "seasonal curtailment" might be required whereby the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity could potentially exceed the design limitations of the system.

As more Rhode Island customers adopt DERs, the dynamism and complexity of the distribution system will continue to increase. DER-related distribution planning and operating issues have already begun to emerge in isolated areas, and they will become more systematic at higher DER penetrations. At the distribution level, upgrades including feeder additions, substation expansions, substation additions, and utilization of higher voltage class distribution feeders have been required to interconnect DERs in targeted areas of high penetration. DER curtailment, although not widespread at this time, will become more common as incremental DER additions exceed system requirements for safe and reliable service.

Q. Why does Rhode Island need to invest in grid modernization?

A. Rhode Island needs grid modernization investments now to meet the three categories of need described in the GMP Business Case and summarized below: (i) operational needs; (ii) customer needs; and (iii) clean energy needs. Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments would be made in an uncoordinated manner, rather than holistically through a comprehensive set of feeder-level investments that provide the highest overall net benefits for customer energy savings, DER integration, and reliability. Transforming Rhode Island's electric distribution system will take time and must proceed thoughtfully and strategically now to avoid widespread issues associated with increased DER interconnections in the future.

Q. Please describe the unmet operational needs driving the need for grid modernization now.

A. Unmet operational needs include enabling cost-effective solutions for distribution system issues caused by customer DER adoption. These issues are localized today, but without grid modernization, they are expected to become systemic in 5-10 years. Grid modernization will enable the Company to cost-effectively address these system issues and provide customers and DER developers with better access to the electric distribution system compared to a future without grid modernization, including reducing DER interconnection cost, improving DER operation, and improving the overall DER experience (e.g., streamlined DER interconnection processes, better customer and third party information sharing and services).

Investments in grid modernization based on a well-coordinated and integrated GMP will allow for an expanded toolbox of solutions to the complex issues arising from high DER penetration and customers' desire for choice and control over their energy needs. GMP investments will allow the Company to not just simply interconnect, but to integrate DERs into distribution system operations for the benefit of all customers.

Q. Please describe the unmet customer needs driving the need for grid modernization now.

A. The Company recognizes that the energy landscape is rapidly changing, and today's customers expect more from their utility. Customers expect their utility to not only provide safe, reliable, and affordable energy, but also increasingly expect cleaner energy options, greater choice and control over their energy use, and delivery of energy services in a simple and convenient way. The Company must invest in grid modernization technologies in order to meet these evolving expectations by providing them with more energy savings opportunities, cleaner energy options, lower-cost DER interconnections, reliability improvements, and greater choice and control in addressing their energy needs compared to a future without grid modernization. Deployment of advanced metering functionality (AMF) in particular will provide customers with the personalized insights and tools needed to better inform their energy decisions and manage their energy costs. AMF coupled with other grid modernization investments will enable more granular operation of the distribution system for the benefit of customers, including lower energy use, cleaner energy, more affordable DER adoption, and improved reliability.

To continue to serve customers under evolving customer behavior and expectations, the transition to managing the grid more granularly, both in time and location, must begin now.

Q. Please describe the unmet clean energy needs driving the need for grid modernization now.

A. Rhode Island's clean energy needs include achieving ambitious clean energy goals like the State's goal of 80 percent greenhouse gas (GHG) emissions reductions by 2050 (i.e., 80x50 goal) established by the Resilient Rhode Island Act, and Governor Raimondo's January 2020 Executive Order 20-01, Advancing a 100% Renewable Energy Future for Rhode Island by 2030 goal (i.e., 100x30 goal).[2]

Grid modernization investments will help Rhode Island meet its clean energy goals by enabling greater customer energy savings and DER adoption. Enabling DER adoption, in particular renewable DG, EV, and EHP adoption, is a key driver for meeting the State's clean energy needs because it will enable customers to reduce their overall carbon footprint, including reducing transportation-related emissions that make up 40 percent of the State's carbon dioxide emissions.[3] Grid modernization investments will help reduce

[2] *See* R.I.G.L. § 42-6.2; *see also* Executive Order 20-01, *Advancing a 100% Renewable Energy Future for Rhode Island By 2030* (January 17, 2020) (setting forth the state's clean energy goals); *see also* Utility Dive, *Rhode Island Governor Wants State To Be Fastest to 100% Renewable Energy* (January 21, 2020) (providing an overview of Executive Order 20-01), https://www.utilitydive.com/news/rhode-island-governor-wants-state-to-be-fastest-to-100-renewable-energy/570700/
[3] *See* U.S. Energy Information Administration, 2017 Data, *Energy-Related CO_2 Emission Data Tables*, at Table 4 (State energy-related carbon dioxide emissions by sector) (Released May 20, 2020), https://www.eia.gov/environment/emissions/state/

the costs and other barriers to interconnect new DERs in Rhode Island (see "unmet operational needs" answer above), which will drive more DER adoption and investment in the State.

These three areas of need - operational, customer, and clean energy - demonstrate that the Company must act now to progress grid modernization in Rhode Island. Taking the next concrete step now will ensure that the electric grid does not hinder customer empowerment or achievement of clean energy goals or create higher costs for customers in the long run.

Q. What will happen if Rhode Island opts not to invest in grid modernization?

A. Taking a "do nothing" approach will negatively impact the State's electric distribution system, customers, and clean energy goals, as summarized below:

- A "do nothing" approach for the distribution system will negatively impact DER interconnections in Rhode Island, with a number of DER projects likely unable to proceed or requiring significant reduction in scale as a result of interconnection and operating costs exceeding their financing ability. Currently, these issues present themselves locally in disparate locations. Over time, as DER penetration increases, these issues will become systemic across the State.

- A "do nothing" approach for customers means lost opportunities for greater insights into and control over their energy use and lost opportunities for substantial energy savings and reliability improvements for all customers.
- And a "do nothing" approach for clean energy will impede renewable DG adoption rates and make EV charging infrastructure more-costly, putting some of the State's ambitious clean energy goals out of reach.

In short, opting not to invest in grid modernization based on a well-coordinated and integrated GMP will make the changes in the electric distribution system already underway more expensive for customers in the long run and less able to generate desired benefits, and will create systemic strain on the electric distribution system. On the other hand, grid modernization based on a well-coordinated and integrated GMP will help maximize operational, customer, and clean energy benefits for all customers.

IV. <u>GMP Overview</u>

Q. What is the purpose of the GMP?

A. The GMP presents a holistic plan of activities and investments that the Company expects to be necessary to manage the electric distribution grid more granularly considering a range of customer DER adoption levels through the period ending in 2030. The GMP consists of a five-year implementation plan, a ten-year roadmap, and a comprehensive

Benefit-Cost Analysis (BCA) for stakeholders to review and the PUC to approve for the purpose of allowing the Company to make grid modernization proposals in the future. The Company developed the GMP with significant input and participation from Rhode Island PST stakeholders over a two-year period.

The Company recognizes that planning over a ten-year time horizon requires flexibility given the significant variables such as the rate of customer DER adoption and the pace of technological advancement. Accordingly, the GMP proposes a flexible and sequenced plan of investments subject to review and adjustment by stakeholders and the PUC throughout the GMP's ten-year horizon.

Q. What is the GMP's scope?

A. The GMP focuses on the distribution planning and operations tools that the Company needs or will need to effectively and efficiently manage the more dynamic loading of the electric distribution grid in Rhode Island safely, reliably, and cost-effectively. Although grid modernization can benefit the New England region's overall energy system, including the electric transmission system, bulk generation, and the heating and transportation sectors, the investments needed to modernize the other parts of the overall energy system outside Rhode Island are beyond the scope of this GMP.

Q. What updates has the Company made to the GMP from its filing in Docket No. 4780?

A. The GMP expands on the investment plan provided in Docket No. 4780 and addresses stakeholder input as required in the ASA. In Docket No. 4780, the Company presented its AMF proposal and a suite of foundational grid modernization investments. The AMF and foundational grid modernization investments presented in Docket No. 4780 are reflected in the GMP Business Case and Updated AMF Business Case in a manner consistent with the ASA.

In addition, the GMP includes a comprehensive set of grid modernization investments through 2030, including investments that would be included in future rate cases and other filings, most notably the Company's annual ISR plans. GMP updates also include external stakeholder feedback, particularly feedback from the PST Advisory Group's GMP and AMF Subcommittee. The GMP provides both a quantitative and qualitative BCA, five-year implementation plan and ten-year roadmap for each category of investment, and additional supporting information including detailed planning analysis results to better describe the distribution system needs and power system, customer, and societal benefits expected from the grid modernization investments.

Q. Does the GMP encompass all of the Company's grid modernization efforts?

A. No. The GMP does not represent the Company's entire capital plan nor does it cover the full range of innovative efforts occurring across the Company. The Company has multiple "modernization" efforts underway across the organization, including programs addressing customer experience transformation, asset management, and work force enablement. Other modernization efforts include asset management and Zero-Sequence Voltage (3V0) initiatives proposed in the Company's ISR plans, the use of specific NWAs in the Rhode Island System Reliability Procurement (SRP) Plans, and the development of customer-facing programs including energy storage and EV programs in Docket No. 4780. The GMP presented here recognizes, aligns with, and complements these initiatives; however, the breadth of many of these initiatives are beyond the scope of the GMP. The GMP focuses on the distribution planning and operations-related investments that are, or will be, needed to effectively and efficiently manage more dynamic loading of the grid safely, reliably and cost effectively.

Q. Does the GMP align with distribution planning efforts?

A. Yes. Identifying grid modernization opportunities to maintain safe and reliable service to customers is, and always has been, an integral element of core distribution system planning. The GMP is a product of distribution planning and is intended to ensure that the electric distribution system can safely, reliably, and cost effectively accommodate the DERs adopted by customers. The Company's planning engineers performed a distribution planning assessment through 2030 in support of the GMP utilizing existing planning criteria.

The analysis performed in support of the GMP required development of new integrated planning processes, as well as new data sets and decision-support tools. The lessons learned from the GMP effort, such as time series load forecasting (i.e., forecasting 8,760 hours each year rather than a handful of peak hours each year) and load flow analysis, will be incorporated into future Area Planning Studies as appropriate.

Q. Please elaborate on how the GMP will leverage future Area Planning Studies.

A. The improved monitoring and control from the deployment of grid modernization (i.e., AMF, Advanced Distribution Management System (ADMS), Feeder Monitoring Sensors, and other advanced field devices) will permit planners to use more granular coincident data in the development of system planning models, where conservative assumptions may have been used as model inputs in the past. These more precise models will improve the analysis that drives Area Planning Studies as well as Interconnection Studies in response to customer load and interconnection applications.

The GMP models used to assess the distribution system impacts due to various future load forecast scenarios required assumptions as to the timing and location of load growth and customer DER adoption. Therefore, for location specific investments, such as the deployment of advanced controls for voltage regulation or relay protection, the GMP can only estimate the expected scale of future need. Detailed deployment plans will be developed through the annual planning process and periodic Area Planning Studies. New technologies discussed in the GMP will be included for consideration in the planners' tool kit and the actual deployment plans for these programs will be presented in future annual ISR plans. Examples of this include the following: prioritization of feeders for advanced field device and optimization application (e.g., Volt-VAR Optimization (VVO) / Conservation Voltage Reduction (CVR), Fault Location, Isolation and Service Restoration (FLISR)) deployments to maximize benefits according to the Docket 4600 Framework, and locations of new protective devices and control upgrades to support reverse power flow to maintain safety and reliability.

Q. How are Company employees equipped to understand, develop and oversee implementation of grid modernization activities?

A. The Company and its employees are committed to delivering a clean, reliable, and affordable energy future for customers. In order to execute this vision, the Company has established internal groups that are responsible for delivering large programs like AMF, ADMS, and other grid modernization investments, including ensuring accountability and best practices are established and followed.

The Company has undertaken efforts to enable and educate employees to understand, construct, and oversee implementation of grid modernization solutions and technologies. The Company has developed and maintains standards and work methods for dealing with the grid modernization equipment and technology. The Company is also integrating grid modernization into the formal training programs for all employees delivered through our Learning and Development organization. The current approach to training includes both local in-person training and engagement and will be supplemented with video and digital training capabilities. Additional training for Control Center personnel has been planned to include ADMS road shows, a sandbox learning environment, as well as multi-day training for all users.

In addition, in order to instill support for grid modernization activities across the organization, the Company has evaluated and begun educating all its employees about grid modernization in the following ways:

- Conducted 34 interviews in 16 different business areas across the Company to help ascertain the level of understanding and buy-in from its employees related to its grid modernization efforts.
- Conducted *Change Management Check In* surveys and found favorable agreement with the Company's efforts in its Case for Change, Change Capability, Culture, Resourcing, Sponsorship & Support, and Training Readiness categories based on responses from nearly 800 employees.

- Developed a Grid Modernization Leadership Video answering questions related to grid modernization. The video is being distributed to all Electric Business Unit (EBU) employees to provide context and an introduction to grid modernization.
- Launched internal communications including "Grid Modernization Minutes" and "Grid Mod Change Story."

Q. What action would the Company like the PUC to take with respect to the GMP?

A. The Company requests the PUC approve the five-year implementation plan, ten-year investment roadmap, and BCA as set forth in the GMP for the purpose of allowing the Company to make grid modernization investment proposals that are consistent with the approved GMP in future ISR plans or rate proceedings. PUC approval of these components will provide regulatory clarity for the Company to undertake the activities described in the GMP.

Q. Is the Company including a request for cost recovery with the filing of the GMP?

A. No. The Company will present cost recovery proposals for specific grid modernization investments to the PUC for review and approval within future ISR plans and rate cases. While the GMP is not seeking cost recovery, an updated business case supporting the Company's AMF proposal is being filed concurrently with the GMP, and the Company will seek approval for cost recovery from the PUC for AMF investments as part of that filing.

Q. Will the Company provide updated BCAs in future filings?

A. Yes. In addition to seeking approval now for the BCA presented in the GMP, the Company understands that it has an obligation to demonstrate that the grid modernization investments have a strong business case, including providing updated BCA results, when seeking cost recovery of the investments in future filings.

V. <u>Stakeholder Engagement</u>

Q. How has the Company engaged with stakeholders to develop the GMP?

A. The Company, in partnership with the Rhode Island Division of Public Utilities and Carriers (the Division) and the Rhode Island Office of Energy Resources (OER), established the PST Advisory Group in October 2018 and formed the GMP and AMF Subcommittee to gather stakeholder input for the development of the GMP and the Updated AMF Business Case, which the Company will file concurrently with this GMP. Subcommittee members include representatives with a variety of interests, as prescribed by the ASA, including advocates for environmental, clean energy, low-income communities, non-regulated power producers, businesses, and community interests.

The meetings covered all topic areas identified as part of the ASA, as well as additional topics raised by stakeholders. The initial phase of formal meetings was held between October 2018 and January 2019. The formal meetings covered specific topics to garner initial stakeholder input and seek alignment of proposals laid out by the Company, such as customer and clean energy needs, future state scenarios, customer value streams, and Docket 4600 alignment, among others. The second phase of meetings, held between February 2019 and September 2020, sought to continue reviewing and refining the Company's proposals while providing additional opportunities for stakeholders to provide feedback on key elements of the Company's plan, including a review of key filing deliverables. Specific to the GMP, the Company also hosted in-depth, deep dive discussions and demonstrations of the GMP's feeder- and state-level distribution modeling and BCA assumptions, methodologies, and preliminary results that allowed stakeholders the opportunity to ask specific questions.

This two-year long collaborative process provided a valuable opportunity to gather and incorporate stakeholder input into the development of all aspects of the Company's proposal. To that end, the Company sought to drive meaningful discussion among members of the GMP and AMF Subcommittee through transparency and responsiveness to stakeholder questions.

Q. How has the Company engaged with the PUC over the course of developing the GMP?

A. The Company, together with the PST Advisory Group, participated in a Workshop at the PUC on April 9, 2019, and Technical Sessions at the PUC on November 5, 2019, and remotely on September 24, 2020, to provide status updates on the various work streams, including the work of the GMP and AMF Subcommittee. At the PUC open meeting on April 23, 2019, Commissioners and Staff provided the Company with feedback on the April 9, 2019 Workshop. This feedback highlighted the PUC's interest in seeing a holistic plan for grid modernization and AMF so the PUC could understand all the costs associated with achieving the benefits listed in the BCA and explore the effects on the proposal of different levels of customer DER adoption.

Q. How has the Company incorporated stakeholders' and the PUC's feedback in developing the GMP?

A. Based on feedback from the PUC and GMP and AMF Subcommittee, the Company added additional milestone meetings and extended the proposed filing date to permit additional stakeholder feedback on the GMP and its integration with the Updated AMF Business Case. The Company also expanded the relevant sections of the GMP and Updated AMF Business Case to address the PUC's stated concerns and the additional input of the GMP and AMF Subcommittee, including by adding a "low customer DER adoption scenario" to explore the effects on the proposal of a wider range of adoption of DERs.

Q. Does the GMP comply with the ASA?

A. Yes. The ASA required the Company to file a comprehensive GMP and identified several elements that the GMP must include. The proposed GMP includes each of these elements, as summarized in Table 1.1 of the GMP.

Q. Does the GMP align with the Docket 4600 Goals?

A. Yes. Table 1.2 in the GMP Business Case explains how the GMP advances each of the Docket 4600 goals for the "new" electric system.

Additionally, the GMP advances the customer-facing goals identified in Docket 4600: empowerment of customers to manage their costs; use of customer education and engagement programs to provide all customers with the information and tools to optimize their electricity consumption; and creation of opportunities to reduce energy burden. The GMP investments, particularly investments in AMF, advance all these goals as well. For example, AMF advanced pricing capability will allow customers to manage their costs by enabling new pricing mechanisms that attribute costs and benefits more equitably; the AMF Customer Engagement Plan (CEP) will educate customers about their energy choices; and AMF Customer Energy Management Portal (CEMP) will provide increased information and tools empowering customers to optimize their electricity consumption. Details are presented in the Updated AMF Business Case.

VI. GMP Approach and Development

Q. What approach did the Company take to select the appropriate grid modernization investments?

A. To select a set of grid modernization solutions that will meet Rhode Island's needs through 2030, the Company followed a stepwise approach. First, the Company identified the GMP goals and objectives based on customers' expectations and the PUC's Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company d/b/a National Grid in Docket No. 4600 (Docket 4600 Guidance Document). Next, the Company developed modeling scenarios using a range of customer DER adoption assumptions with varying levels of renewable DG interconnection and beneficial electrification adoption through 2030. Once these were developed, a future state assessment was conducted to study these scenarios, which led to a set of necessary grid modernization functionalities and potential benefit impacts. Then, the Company identified a proposed solution set and ten-year roadmap necessary to realize those functionalities and benefit impacts. Finally, the Company developed a detailed BCA based on the solutions identified in the ten-year roadmap and internal estimates for the costs and benefits of the portfolio of solutions. The BCA is discussed later in this testimony and in detail in Section 8 of the GMP Business Case.

Q. What vision of the future did the Company use in developing the GMP?

A. The Company's vision focused on the confluence of factors that has led to the need for grid modernization investments: Customers are adopting DERs at increasing rates; customers' expectations are evolving with respect to having greater choice, control, and affordability; state policy objectives seek greater integration of clean energy alternatives; and technologies are available or under development to manage the grid more granularly. With these opportunities in mind, the Company envisions a future with greater DER penetration than today, in which customer DERs can be managed to improve the affordability and efficiency of grid operations. The scope and scale of customer DER adoption is a key variable in this vision and is, for the most part, beyond the direct control of the Company. Therefore, the Company has considered multiple future state scenarios of DER adoption rather than a single static forecast of the future to develop its vision for the GMP.

Q. Please elaborate on the future state scenarios that the Company considered in developing the GMP.

A. While the Company expects a high-DER adoption future, there is uncertainty with respect to where and when DER interconnections will occur. Therefore, the Company developed two primary customer DER adoption scenarios to "bookend" a range of possible future outcomes: 1) low customer DER adoption (i.e., Low DER) scenario based on historic (2018-2020) DER adoption rates with an annual reduction in renewable DG adoption over time; and a 2) higher DER adoption (i.e., High DER) scenario consistent with achieving Rhode Island's 2050 goal of 80 percent greenhouse gas emissions reductions compared to a 1990 baseline.

The DER adoption assumptions in the Low DER Scenario are equivalent to the "Low Case" of the Company's 15-year distribution planning forecast.[4] The Company assessed the probability of the Low Case occurring to be between 5-20%, depending on the DER load forecast. Specifically, solar DG, EV, and demand response forecasts were assigned a probability of 5% each; Energy Efficiency was assigned a probability of 10%; and EHPs, which do not have a significant impact on the overall GMP cost or benefit assessment through 2030, were assigned a probability of 20%.

The DER adoption assumptions in the High DER Scenario are consistent with the "High Case" of the Company's 15-year distribution planning forecast and are similar to Rhode Island's Executive Climate Change Coordinating Council (EC4) Greenhouse Gas Emissions Reduction Plan. The Company assessed the probability of the High Case occurring to be between 5-35%, depending on the DER load forecast. Specifically, solar DG forecast, which has a significant impact on the overall GMP cost and benefit assessment, was assigned a probability of 35%; EV forecast was assigned a probability of 10%; and Energy Efficiency, Demand Response (DR), and EHP forecasts were assigned a probability of 5% each.

[4] *See* The Narragansett Electric Company, *2021 Electric Peak (MW) Forecast, 15-Year Long-Term 2021 to 2035* (Rev1, Jan. 6, 2021), https://ngrid.apps.esri.com/NGSysDataPortal/RI/index.html

Considering these scenarios, the Company evaluated the potential future DER impact on state-wide load curves for each hour of the year through 2030. Additionally, the Company created detailed distribution load flow models on a small representative sample of distribution feeders to identify the scale and magnitude of local operational constraints that would arise under the various loading scenarios with and without grid modernization investments out to 2030.

Q. What did the Company conclude based on the future state assessment of these scenarios?

A. Based on the future state scenario assessment, the Company determined that the current levels of renewable DG adoption will need to continue, and beneficial electrification adoption will need to increase significantly to achieve the 80x50 goal. The Company also made the following key findings based on the feeder-level assessment of the Low DER and High DER scenarios:

- Distribution operating issues, which are already emerging in isolated areas in Rhode Island, will become more systemic at higher DER penetrations.
- Although there will be some coincidence between commercial "workplace" EV charging and the timing of solar DG injections, there is generally a mismatch between solar DG injections and typical late day and evening residential EV charging.

- High levels of renewable DG adoption will impact the grid more significantly during light loading (e.g., off-peak) periods than peak periods. During light loading periods, significant renewable DG curtailment may be required.
- High penetrations of DER will significantly impact voltage regulation: beneficial electrification will lead to more low voltage violations, and renewable DG injections will lead to more high voltage violations during light loading periods. Therefore, advanced voltage control schemes will be required to manage voltage during both on-peak and light loading periods.
- Significant swings in loading and the increasing prevalence of two-way power flows caused by renewable DG will require more adaptive relay protection schemes to properly coordinate circuit breakers to ensure worker safety and the reliable operation of the grid.
- The Company will need enhanced data handling and processing power for both distribution system planning and real-time grid operations. For this GMP study, a labor-intensive manual process was used that will not be sustainable at scale.

The technology to operate electric grids has advanced, making this the appropriate time to implement new solutions that will address today's constraints cost-effectively while being flexible enough to expand in capability to address future needs and opportunities as they evolve.

VII. Overview of Proposed GMP Investments

Q. What grid modernization investments are necessary to integrate the growing number of DERs cost effectively and in a manner that will yield net benefits to customers?

A. The GMP outlines the portfolio of projects and initiatives that the Company expects to be necessary to leverage customer data and manage the distribution grid more granularly to 1) give customers more energy choices and information; 2) ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term; and 3) build a flexible grid to integrate more clean energy generation.

The GMP reflects continued investment in the foundational grid modernization technologies approved in Docket No. 4770, including for the Rhode Island System Data Portal, Geographic Information Systems (GIS) Data Enhancements, ADMS Core Functionality, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management).

The GMP also envisions new grid modernization investments in AMF, Advanced Field Devices (i.e., Feeder Monitoring Sensors, Advanced Capacitors and Regulators, Advanced Reclosers and Breakers), Advanced ADMS Applications (i.e., Protection and Arc Flash, Integrated VVO/CVR, FLISR), Operational Telecommunications (OpTel)

Strategy, Distributed Energy Resource Management System (DERMS), and Innovation and Technology Readiness (ITR) projects.

Q. What does the Company propose as the timeline for these investments?

A. The 2030 Roadmap presents a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing and approved investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Telecommunications (Network Management); as well as development and deployment of new investments in AMF, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), OpTel Strategy, and DERMS. Likewise, the installation of Advanced Field Devices (i.e., feeder monitoring sensors, and advanced capacitors, regulators, reclosers, and breakers) and VVO/CVR will be identified and recommended via traditional planning processes and incorporated into the Company's capital investment plans and annual ISR filings.

This approach will allow the Company to address evolving customer expectations and leverage new technologies, programs, and services to meet customer needs. Project plans for future investments will be presented in their appropriate forums at the appropriate time throughout the horizon of the GMP. This iterative process enables on-going engagement and review and greatly reduces risks. The Grid Modernization Roadmap presented in *Section 5.7: 2030 Roadmap* of the GMP Business Case summarizes the solutions, expected timing, and expected filing for cost recovery of GMP investments over the next ten years.

Q. What is the level of maturity and corresponding implementation detail of the project/program investments identified in the GMP?

A. The GMP includes projects at different levels of maturity. Projects in the initial years of the plan are relatively mature and have detailed implementation plans, whereas investments later in the plan, or those that will be scaled in response to system needs through traditional planning cycles, are in some cases less mature (e.g., Protection and Arc Flash Application, DERMS) and have less detailed plans at this time.

Q. Why does the Company propose new investment in AMF?

A. AMF is a foundational component of the GMP. The Updated AMF Business Case, filed concurrently with the GMP, provides the Company's justification for investment in AMF. In brief, the Company's current metering infrastructure, which primarily leverages automated metering reading (AMR) technology, is incapable of meeting evolving customer expectations and the increasingly granular needs of the distribution electric grid. For example, current AMR meters cannot provide energy usage data with the granularity or frequency required to deliver personalized energy insights and recommendations or to provide the actionable information needed to support improved grid management. Furthermore, approximately 60 percent of the electric AMR meters currently in the field will reach the end of their estimated 20-year life during calendar years 2023-2024 and will need to be replaced.

Investment in AMF will address these needs by empowering customers enhanced understanding, choice, and control over their energy consumption. Toward this end, AMF will enable them to reduce energy usage through greater insights about their energy cost drivers, personal usage, and new product and service offerings. AMF data and remote capabilities will also provide support to grid-side applications within the scope of the GMP, increasing operational efficiency, and better supporting the integration of DERs.

Additional information is included in the Updated AMF Business Case and the pre-filed joint testimony of Company witnesses Kristoffer P. Kiefer and Stephen Lasher.

Q. Why does the Company propose to continue investing in the Rhode Island System Data Portal?

A. The Company considers the System Data Portal (Portal) to be an important investment to align with the need for improved data and transparency to Company planning information. The initial version of the Portal has been established, can be accessed online,[5] and currently provides information on Company Reports (planning process and criteria, load forecasts, and completed distribution planning area studies), Distribution Asset Overview (a geographic overview of distribution circuits including technical specifications of circuits and substations), Heat Maps (a geographic representation of circuit loading), Hosting Capacity (a geographic representation of DER hosting capability by distribution feeder), and NWAs (a link to National Grid's central NWA website for information on non-wires alternative opportunities).

The content of the Portal is expected to expand and evolve over time as new tools, data, and analysis are developed. The Company has delivered and continues to maintain the Portal as part of the ASA. The Company recovered the costs for tasks associated with the Initial Version of the Portal, and the Initial Version of the Hosting Capacity Map through the 2018 System Reliability Procurement (SRP) Report filing. The Company is currently recovering operational and maintenance expense for full implementation and continued support costs for the Portal through base distribution rates approved as part of the ASA.

Q. Why does the Company propose investment in Feeder Monitoring Sensors?

A. The dynamic impacts of DER on the distribution system's performance require granular understanding of voltage, loading, and other characteristics of various parts of the distribution system (i.e., situational awareness) to assure service is maintained within

[5] The System Data Portal can be accessed online at https://ngrid.apps.esri.com/NGSysDataPortal/RI/index.html.

acceptable service quality standards in an efficient manner. In the absence of data, operators and distribution system planners must make conservative assumptions with respect to the coincidence of load and DER operation, leading to more restrictive hosting capacity assessments and less than optimal operational actions. Feeder Monitoring Sensors (Sensors), in combination with other investments described in the GMP, provide more accurate data for hosting capacity calculations, which benefit DG and other DER customers and providers looking for the most economical locations for their projects. In addition, the near real-time power measurements provided by these Sensors enable engineering and operations personnel to better manage capacity and voltage along individual feeders, ultimately resulting in lower costs to all National Grid customers through optimization (e.g., VVO/CVR, FLISR).

The Company has been deploying remote interval monitoring sensors and control for new substations and feeders for several years. To date, the Company has deployed 44 Feeder Monitoring Sensors on 19 feeders from 6 substations in Rhode Island as part of the Company’s VVO/CVR Pilot program. Deployment on an additional 14 feeders is anticipated through the Company’s FY 2021 ISR Plan. The GMP proposes investment in interval Feeder Monitoring Sensors on between 60-100% of primary distribution feeders, at least at the head of the feeder at or near the substation, for compliance with voltage and thermal protection requirements as customer DER adoption grows.

Q. Why does the Company propose investment in Advanced Capacitors and Regulators?

A. For a customer's electrical equipment to operate as expected, it must be connected to a source that is operating within an allowable voltage range. In the past, voltage regulation was relatively predictable. Since electrical resistance of the system and the load cycles were very predictable, the control settings on capacitors and regulators were simple, autonomous, and only needed to be adjusted occasionally in concert with periodic planning reviews. These simple autonomous settings, however, will be insufficient to maintain compliance with voltage standards for feeders with a high level of intermittent renewable generation and two-way power flows. Specifically, load-based DERs, such as EVs, are forecasted to create under-voltage issues during peak load periods, and generation-based DERs, such as solar and wind DG, are forecasted to create overvoltage during light load periods. The proposed Advanced Capacitors & Regulators would adjust system voltages up or down in a dynamic manner to accommodate the variable output of these DER technologies. In addition, the voltage control and near real-time power measurements provided by these devices enable engineering and operations personnel to better manage capacity and voltage along individual feeders, ultimately resulting in lower costs to all National Grid customers through optimization (e.g., VVO/CVR).

To date, the Company has deployed 122 advanced capacitors and 52 advanced regulators on 19 feeders from 6 substations in Rhode Island as part of the Company's VVO/CVR

Pilot program. Deployment on an additional 14 feeders is anticipated through the Company's FY21 ISR Plan. The GMP proposes investment in Advanced Capacitors & Regulators on between 60-100% of primary distribution feeders for increased customer energy savings and compliance with voltage protection requirements as customer DER adoption grows.

Q. Why does the Company propose investment in Advanced Reclosers and Breakers?

A. The distribution system has traditionally been built to ensure adequate available capacity at all times by building the necessary distribution system capacity to accommodate forecasted peak loading on extreme weather days in accordance with the Company's planning criteria. Designing the system to meet these worst-case scenarios assuming one-way power flow eliminated or lessened the need for day-to-day load management for distribution grid management. However, new DER loads do not align well with traditional load shapes, and DER can be located anywhere on the distribution system, resulting in possible two-way power flow, overloads in the reverse direction under light load conditions, and desensitization of protection systems during fault conditions. Similar to voltage management, the increasing complexity of the grid will require a transition away from simple autonomous controls to control schemes that are integrated across an entire feeder.

The proposed Advanced Reclosers & Breakers would adjust system power flow in a dynamic manner to accommodate the variable output of these DER technologies. In addition, the load control and near real-time power measurements provided by these devices enable engineering and operations personnel to better manage capacity and voltage along individual feeders, ultimately resulting in lower costs to all National Grid customers through optimization (e.g., FLISR).

To date, the Company has deployed 453 advanced reclosers on over 200 feeders in Rhode Island as part of customer requests for DER interconnections (22 midline reclosers and 66 point of common coupling reclosers)[6] and Company reliability improvement programs (365 midline reclosers). The GMP proposes investment in Advanced Reclosers & Breakers on between 60-100 percent of primary distribution feeders for increased reliability and compliance with thermal protection requirements as customer DER adoption grows.

Q. Why does the Company propose to continue investing in GIS Data Enhancements?

A. GIS is a geographic-based technology that combines the power of maps with the function of a database. The Company currently utilizes GIS as its authoritative source for distribution asset information and network configuration (i.e., "connected model"). GIS information is utilized in several business processes including distribution system project

[6] Point of common coupling or "PCC" means the point where the generating facility's local electric power system connects to the utility's electric system.

design, load flow modeling, outage management, and analysis models. As grid operations increasingly require granularity, accuracy, and timeliness of data to achieve the benefits associated with advanced systems functionality, GIS will be the foundation on which many of these systems are built.

While the existing GIS and data sets maintained by the Company have been fit-for-purpose to date, the introduction of new uses for GIS integration, such as for ADMS applications and hosting capacity analysis, requires change. Without addressing the data as well as system performance and functionality requirements, the Company cannot take full advantage of the benefits that ADMS and advanced analytics platforms offer. Implementing the GIS Data Enhancement project will enable network models to be developed consistently and efficiently for distribution system planning, hosting capacity analysis, and operations utilizing ADMS. These efforts are foundational to enable the desired granular, accurate and timely management of the grid envisioned in this GMP.

GIS data improvements and data hardening are underway. This work includes field data verification, data validation, making required changes, and implementing a data quality monitoring process. In addition, changes to baseline GIS to allow for new asset types, new equipment, expanded attributes, and characteristics is also in progress. Going forward, GIS data cleanup and data model changes will continue and changes to GIS to support these requirements for ADMS will be progressed.

Q. Why does the Company propose to continue investing in ADMS Core Functionality?

A. Currently, operators rely on static system models and the distribution status information in SCADA (where available) to make operations decisions. For planned and emergency feeder reconfigurations, the operators utilize historic data, such as seasonal peak loading information, to help predict future conditions. Historically, system loading patterns have been somewhat predictable with regions, substations, and even individual feeders generally following similar trends. This is changing with the proliferation of DER, and locational variability is increasing.

In addition, any advanced automation schemes (e.g., VVO/CVR) are currently built as stand-alone functions. The operators can monitor the actions of the programs via the SCADA system, but they run independently based on "as-designed" feeder configurations rather than adapting to the real-time "as-switched" feeder configuration. This means that these automated schemes may be disabled for any configuration of the distribution grid out of its normal "as-designed" state.

Finally, over the last decade, the Company has deployed a growing number of field devices integrated with the existing SCADA system (e.g., Feeder Monitoring Sensors, Advanced Capacitors & Regulators, Advanced Reclosers & Breakers), such that the amount of data brought back from distributed devices has increased significantly. This proliferation of remote telemetered devices on the distribution system is already straining the capacity of the existing SCADA system, which includes both transmission and distribution (T&D) device data.

Q. Please elaborate on the proposed ADMS investment.

A. The proposed ADMS investment is an integrated grouping of hardware and software necessary for Distribution Control Center operations to provide greater visibility, situation awareness, and optimization of the electric distribution grid as well as improved efficiencies through automating multiple control center processes. The Company believes ADMS is a critical platform for the integration and operational management of DERs as their impact on grid performance grows, and ADMS will incorporate real-time data into useful solutions from an ever-growing number of Advanced Field Devices, DERs, and AMF data as it becomes available. For example, when planning to reconfigure the grid, ADMS will allow the operators to simulate the future state (i.e., reconfigured grid) to test the reconfiguration approach and ensue the most efficient switching that yields optimal power quality. DERs will be operationally integrated into the ADMS network model to allow operators to assess their effect on the grid, as well as leverage them for support where possible.

In addition, ADMS will become the platform that coordinates multiple functions on a common "as-switched" network model. By incorporating control and automation capable grid devices (e.g., Advanced Capacitors & Regulators, VVO, and FLISR) with the centralized ADMS platform, these technologies can operate in abnormal grid configurations, further supporting operations and adding value. Finally, the deployment of a new DSCADA system will enable management of the proliferation of data from remote telemetered devices on the distribution system to ensure continued reliability.

The project will be implemented utilizing a phased approach putting different modules and functionality into service over the next five years. This will maximize value add and benefits realization as early as possible as well as help to align ADMS with critical dependencies such as GIS and data model expansion and RTU separation. To date, the Company has completed an analysis and scoping effort for the development of the ADMS, including capturing business capabilities and requirements, analyzing affected operational procedures and training requirements, selecting vendors, procuring hardware and software, and building/testing infrastructure.

Q. Why does the Company propose to continue investing in Underlying IT Infrastructure?

A. Managing the distribution system more granularly in order to safely, reliably, and cost effectively meet customer's evolving expectations will depend on the Company's ability to manage, analyze, and share underlying information or data. Managing high levels of DER integration while ensuring electrical network stability and performance will rely on deeper and faster insight into asset performance, operating conditions, and customer demand. As the Company deploys more Advanced Field Devices, AMF, and other technologies, there will be an enormous growth of incoming data. The following Underlying IT Infrastructure investments in Data Management, Enterprise Integration Platform, and Corporate PI Historian are necessary to enable grid modernization functionalities and realize its full benefits.

Data Management: Future investments will build foundational data management capabilities by enabling enhanced data governance across key datasets. This project will implement necessary data management tools and processes to ingest data, catalog data, and assess and improve data quality. This centralized platform will be used to measure/monitor critical data elements and their accuracy, integrity, completeness, and consistency to support continuous data improvement. Setting this foundation is critical to establishing the longer-term vision of a data management platform, which will be necessary in the future as the amount of data collected and need for data continues to grow.

Enterprise Integration Platform: Grid modernization applications will leverage the Enterprise Integration Platform to integrate various objects within and outside the Company to enable secure exchange of information between systems, services, and devices. This investment will provide all the necessary integrations between the various grid modernization applications such as ADMS, Telecommunications Operations Management System (TOMS), and VVO/CVR; corporate applications such as GIS; and external applications as necessary.

Corporate PI Historian: Future investments will permit engineering, asset management, and advanced analytics teams secure access to this information without affecting performance of the operational systems. The environment will be used to support internal modeling, analysis, and reporting needs. In addition, this project will allow the Company to consolidate data currently stored in separate systems and data stores, reducing complexity and enabling further analytical insights.

To date, the Company has completed an architecture assessment of the current integration tools in use, and their fitment for the Grid Modernization Program. The program level conceptual solution has been established to address the needs of the Enterprise Integration Platform and Data Management. Integration Platform infrastructure and license components have been provisioned, and the first set of reusable integration frameworks, adapters and services are currently in development. Work on Corporate PI Historian has not yet begun.

Q. Why does the Company propose to continue investing in Appropriate Cyber Services?

A. The Company considers cybersecurity a necessary capability in order to operate a safe, reliable and cost-effective electric distribution system. Cybersecurity protects customers and electric grid operations from a vast array of threats. As more intelligent devices, including third-party devices, are interconnected and integrated with utility operations, the number of potential targets increases, as does the need for a robust cybersecurity program.

The Company proposes a risk-based cybersecurity approach that encompasses people, processes, and technologies and that recognizes that the electric grid is changing from a relatively closed system, to a complex, highly interconnected environment. The Implementation Plan details the specific proposed investments.

To date, applicable cyber security threats have been mapped to the grid modernization business capabilities to assess how they may be impacted by those threats if they were to be realized. In addition, the implementation plan for the integration of cyber security services and the grid modernization workstreams have been drafted to ensure services are available when needed. During the next rate year, Appropriate Cyber Services will be deployed and/or enhanced to support the grid modernization workstreams, and detailed requirements and design will be started. Elements of cyber security have already been delivered as part of the Enterprise Service Bus investments (part of Enterprise Integration Platform).

Q. Why does the Company propose continued and new investment in Telecommunications?

A. A secure and robust OpTel network is a foundational element to the GMP. The Company currently utilizes several different communications technologies for the collection of customer meter and transmission and distribution system data. The existing communication networks that support these functions are suitable for grid data requirements at the current time. However, these networks must be upgraded and expanded to support future grid modernization and enable greater reliability, control, monitoring, and security of the distribution assets.

Considering the breath of communications options and the evolution of technology, the Company understands that a flexible strategy is required when deploying communication systems. In particular, the OpTel system must be designed in a fashion that permits an efficient refresh of network technologies. No single telecommunications and networking system will economically meet all requirements in all areas. Therefore, the Company is planning for a private network across the service territory that provides coverage in a reliable and economic manner.

The proposed OpTel Strategy includes investments to build out and operate a private network, which will provide the majority of communications for the new distribution devices such as those supporting customer DERs. Aside from the added benefits of greater network control and reliability in transitioning from a public carrier solution to a private one, a key driver of this change is to reduce long-term costs (i.e., commercial cellular run-the-business (RTB) costs) that increase with every new grid device added. Given the increasing adoption of DG and future EV adoption, plus the grid modernization initiatives needed to support these, the Company anticipates a significant number of endpoint nodes that will need connectivity.[7]

The large increase in connected devices anticipated in the future would result in significant commercial cellular RTB costs if investments are not made in OpTel Strategy. With significant future cost coming from increasing cellular connectivity, this is the appropriate time for the Company to invest in a private network.

The Company must also enhance its ability to plan and manage the growing class of controllable assets. As part of the approved Telecommunications (Network Management) investment, the Company is reviewing its current methods, which lack features for graphical and logical circuit planning, design, and evaluation. Adding new tools and developing interfaces to current systems will improve maintenance and operations.

[7] Considering the two bookend DER adoption scenarios, the Company anticipates that an additional 2,400 new distribution devices under the Low DER Scenario (primarily advanced field devices) and 11,400 new distribution devices under the High DER Scenario (primarily EV charging devices) will need to be outfitted with telecommunications and be connected into the Distribution Control Center systems.

To date, significant work has been initiated in evaluating new core network equipment (Tier 1 & 2), developing a private wireless network solution (Tier 3), evaluating incremental telecommunication bandwidth investments, and procuring and setting up TOMS that will maintain all telecommunications equipment and services (Network Management). For the greatest operational efficiency, each initiative is being developed across National Grid's Rhode Island, New York, and Massachusetts service areas because the same technology solutions and approaches are being considered and proposed for each state.

Q. Why does the Company propose investment in VVO/CVR Platforms?

A. VVO benefits customers by reducing demand and energy use through CVR.[8] The VVO control schemes coordinate multiple voltage regulating devices of a feeder to achieve optimal CVR performance. On average, expected benefits are estimated to be about 3% reduction in energy and peak demand on feeders equipped with Sensors, Advanced Capacitors & Regulators, and the VVO/CVR Platform. Customers realize benefits through reduced costs for electric energy and system capacity, which result in lower bills compared to a future case without the VVO/CVR Platform.

The Company currently uses a stand-alone VVO controller for its VVO deployments but anticipates transitioning to an ADMS-based VVO/CVR solution to reduce costs and gain

[8] CVR enables the operation of distribution feeders at lower overall voltages to reduce electricity consumption from customer appliances.

efficiencies due to automation onto a single control platform with an "as switched" network model allowing optimized solutions when the grid is in abnormal states. The Company anticipates that a VVO application will be incorporated in the third phase of the ADMS project. Also, in that same time frame, the Company expects customer-level voltage information to be available through AMF and believes an incremental 1% reduction in energy and peak demand can be achieved if this more granular voltage data is used to fine tune the VVO control scheme.

To date, the Company has implemented VVO/CVR on 19 feeders from 6 substations in Rhode Island. Deployment on an additional 14 feeders is anticipated through the Company's FY 2021 ISR Plan based on the initial positive results. VVO/CVR deployment is expected to increase to between 20-36 feeders per year as early as FY23 in coordination with the Sensor and Advanced Capacitor & Regulator deployments described earlier.

Q. Why does the Company propose new investment in Fault Location, Isolation and Service Restoration (FLISR)?

Investment in FLISR will help the Company continue to provide reliable service to customers by reducing the duration of service interruptions. As more reclosers with advanced controls are deployed and integrated with the Distribution Control Center systems, the automation of isolation and service restoration is possible. Switching steps that could take an hour or more may be possible in less than one minute. To achieve this, feeder tie switches will need to be outfitted for remote control and a centralized FLISR control scheme application enabled on the ADMS platform. The Company intends to identify targeted FLISR field deployments through planning studies incorporated into annual ISR plans considering the expected impact on customer interruptions and customer minutes of interruption that could be saved through automation. FLISR deployment will be coordination with the Sensor and Advanced Recloser & Breaker deployments described earlier.

Q. Why does the Company propose new investment in DERMS?

A. Under high customer DER adoption scenarios, a suite of DERMS tools are necessary to integrate customer controlled DER resources with grid operations. The Company expects that the scope and scale of DERMS functionalities will increase and evolve as customer DER adoption increases and new programs for load management (e.g., DR, flexible DG, EV charging, energy storage, microgrid coordination) become available. The flagship role of a DERMS is to dispatch DER in a manner that maintains the security of the distribution system while ensuring an optimal economic solution. To do so, DERMS must have functionalities that include resource registration, forecasting, resource optimization, activation, measurement and verification and settlement.

An objective of the GMP is to better leverage DER and customer programs, including demand response but also flexible DG, EV charging, and energy storage programs, in support of distribution grid operations for the benefit of all customers. As such, the long-term plan is to expand and enhance the types of resources that can be managed through a DERMS and to integrate DERMS with ADMS to optimize distribution grid performance. The Company expects that DERMS functionalities will be deployed as the applications become available and are beneficial to support grid and market operations.

Q. Why does the Company propose new investment in ITR Projects?

A ITR Project investments will fund the pilot projects necessary to support cost-effective deployment of the future grid modernization investments presented in the GMP, particularly investments that are less-well defined, like DERMS, or investments with emerging functionality that can be further explored to increase net benefits, like the System Data Portal, AMF, ADMS, VVO/CVR, or FLISR. This approach is similar to the Company's successful VVO/CVR Pilot program being funded through annual ISR filings. ITR projects will enable the Company to work with the industry to evaluate and test early versions of some of the future GMP solutions and functionalities on a small scale, so the most cost-effective and beneficial functionalities and use cases can be developed for large-scale deployment.

VIII. <u>Benefits/Cost Analysis</u>

Q. How did the Company account for the benefits of Grid Modernization?

A. Many of the GMP benefits have been quantified using the Docket No. 4600 Benefit-Cost Framework (the Docket 4600 Framework) the PUC adopted in Docket No. 4600[9] based on detailed analysis, including detailed feeder-level and state-level modeling of the future state scenarios. Where the Docket 4600 Framework did not provide full guidance, the Company used well-established BCA methodologies from other Company BCA efforts, including the Energy Efficiency Program's BCA and Rhode Island Test. The source for many of the avoided cost value components is the ASEC 2018 Study, *Avoided Energy Supply Components in New England: 2018 Report* prepared by Synapse Energy Economics for AESC 2018 Study Group, October 24, 2018. In many cases, the quantifiable benefit is an avoided cost that is calculated based on the difference (or "delta") between a Reference Case and the Grid Modernization cases.[10]

In cases where benefits cannot be quantified due either to lack of data or lack of accepted method, the Company conducted a qualitative analysis of benefits, consistent with the Docket 4600 Framework. These qualitative benefits, if considered as part of the overall

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[9] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates in Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 at 23 (July 31, 2017).

[10] Note that the BCA does not include benefits (or costs) associated with the future DER deployments compared to today (e.g., future decrease in GHG emissions reduction due to renewable DG adoption), only benefits compared to the Reference Case, which is assumed to have the same level of DER adoption (i.e., installed renewable DG nameplate) as the Grid Modernization cases.

BCA, increase the benefit-cost ratio and potentially make the grid modernization investments even more valuable and cost-effective for customers.

Q. How did the Company identify the potential benefits of the GMP investments?

A. The Company surveyed internal and external BCAs for similar investments, including several other AMF and grid modernization plan utility filings to understand the scope of the BCA and provide a benchmark for benefit and cost categories to be included in the Company's BCA. The results of the survey, included in the Appendix to the GMP, show that the scope and breadth of the Company's BCA for Rhode Island is more thorough than the other filings in the survey as a result of the Company having applied the Docket 4600 Framework and detailed modeling of a future distribution system in Rhode Island.

Q. What benefits did the GMP quantify?

A. The GMP BCA quantifies and monetizes the following categories of benefits:

Avoided O&M Costs

- OPEX Labor Efficiency: Improvements in operational efficiency, such as eliminating AMR meter reading, or reducing meter investigations and visits to connect and disconnect service.

- Avoided Legacy OPEX Investments: Avoiding "legacy" OPEX system investments, including RTB telecoms costs from existing Advanced Field Devices and future DERs, due to the proposed grid modernization investments.

Avoided Capital Costs

- Avoided Legacy CAPEX Investments: Avoiding "legacy" CAPEX system investments, such as AMR hardware replacement and installation costs, due to the proposed grid modernization investments.
- Avoided D-System Infrastructure Cost: Improvements in load optimization due to the ability of the system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs, rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption.

Customer Benefits - Empowerment

- Improved Customer Choice & Control: Improvements in customer energy usage information sharing, third party information sharing, and access to third party service providers, which empowers customers to better understand and prioritize among solutions to best manage energy usage and costs.

- Improved DER Experience: Improvements that enable an improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes, flexible interconnection options, reductions in time to interconnect, and better customer and third-party information sharing and services.
- More Equitable Cost Allocation: Improvements in the ability to allocate costs to different classes of customers in a way that more precisely reflects their respective contributions to system-level costs and will support development of more cost-reflective rates and pricing that limit cross-subsidization.[68]
- More Equitable Benefit Allocation: Improvements in the ability to allocate benefits to compensate customer- or third-party owned DERs in a way that is more reflective of actual system benefits (e.g., shift from current net energy metering programs to location- and market-based DER pricing).

Customer Benefits – Energy Savings

- Reduced Customer Energy Use: Reductions in electrical energy used by a customer, which can be a result of customer action based on enhanced energy use insights (e.g., AMF-based High Bill Alerts) or integrating AMF with in-home technologies; or utility action, such as operating distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption from customer appliances (e.g., VVO/CVR).

- Reduced System Capacity Requirements: Reductions in system capacity requirements in either the generation, transmission or distribution systems, which can be a result of customer action based on enhanced energy use insights (e.g., AMI-based High Bill Alerts), integrating AMF with in-home technologies, or responding to TVR to reduce demand for energy during peak demand periods; or utility action, such as operating distribution feeders at lower overall voltages (within ANSI limits) to reduce peak demand from customer appliances (e.g., VVO/CVR).

Customer Benefits – Reliability Improvements

- Reduced Outage Notification Time: Reductions in customer outage durations due to AMF remote metering and the ability of the system operator to quickly identify an outage and reconfigure the system rather than waiting for phone calls from customers to identify an outage.
- Reduced Outage Restoration Time: Reductions in customer outage durations due to the ability of the system operator and control system to quickly generate switch orders (i.e., ADMS-based SOM) or locate and isolate a fault and restore power (e.g., FLISR) rather than waiting for field crews to locate and restore power.

Customer Benefits – Avoided Bulk Energy Purchases

- Reduced DG Curtailment: Reductions in DG curtailment during the interconnection application stage or during operations due to the ability of the system operator to manage DERs and optimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints.

Societal Benefits

- Reduced Customer Energy Use: Reductions in non-embedded central power plant emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), and oxides of nitrogen (NO_x) resulting from reductions in electrical energy used by a customer, which can be a result of customer action (e.g., AMF-based High Bill Alerts) or utility action (e.g., VVO/CVR).
- Reduced DG Curtailment: Reductions in non-embedded central power plant emissions of CO_2, SO_2, and NO_x resulting from the ability of the system operator to manage DERs and optimize power output from renewable DG rather than relying on seasonal DG curtailment to avoid thermal or voltage constraints.

Q. How does the Company quantify the value of enabling greater DER integration?

A. A fair comparison of the grid modernization investments to the counterfactual case without grid modernization (i.e., Reference Case) requires customer DER adoption be an exogenous variable in the GMP BCA. Therefore, the Company did not attempt to estimate the difference in the amount of renewable DG that could be interconnected in the grid modernization cases compared to the Reference Case, where many DG projects are likely to be uneconomic by 2030 under high DER adoption scenarios. Instead, the

Company quantified the value of enabling greater DER integration using two of the benefit categories summarized above:

- Avoided D-System Infrastructure Cost benefit based on the difference between the estimated traditional infrastructure upgrade costs necessary to accommodate future DG interconnections in the Reference Case compared to the grid modernization cases
- Reduced DG Curtailment benefit based on the difference between the estimated seasonal curtailment in the Reference Case and the optimized power output (i.e., granular curtailment) that is possible in the grid modernization cases

Q. What costs were included in the GMP BCA?

A. The Company developed estimates for all incremental Company costs necessary to deploy and maintain the grid modernization investments through the end of the 20-year BCA evaluation period (FY22-FY41), including capital expenditures (CAPEX), operating expenditures (OPEX), and RTB costs for all solutions presented in the GMP roadmap. There were no incremental customer costs identified as being necessary to enable the GMP compared to the Reference Case.

Q. Do the envisioned benefits of grid modernization investment outweigh the costs?

A. Yes. The Company estimates that the quantified benefits of the proposed GMP investment outweigh the costs by over 50 percent (Benefit-Cost Ratio (BCR) = 1.51) in our base case future scenario with low customer DER adoption and by 160 percent (BCR

= 2.60) in our base case future scenario with higher customer DER adoption. In addition, the GMP discusses a number of additional benefits from the proposed investments, including Economic Development, Enhanced Load Shift, Rest-in-Pool DRIPE, Customer Empowerment and Choice, and Prosumer Benefits, that are not included in the base case BCR estimates but are addressed qualitatively or as a sensitivity analysis.

Q. Based on the BCA results, should the PUC approve the GMP?

A. Yes. The Company requests that the PUC approve the GMP as a roadmap for grid modernization investments over the next ten years, and the accompanying BCA. Not only do the GMP investments realize significant quantifiable benefits compared to not investing in grid modernization, including reduced customer energy use, outage restoration time, DG curtailment, and avoiding certain O&M and capital investment costs, but the Company also believes the investments will further the customer experience and facilitate choice and control.

IX. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

GMP Business Case

Schedule SL-1

Table of Contents

Executive Summary

The Narragansett Electric Company d/b/a National Grid (National Grid or the Company) is pleased to share this 2021 Rhode Island Grid Modernization Plan (GMP). The GMP is an informational guidance document that presents a holistic plan of activities and investments expected to be necessary to manage the distribution electric grid more granularly considering a range of Distributed Energy Resources (DER)[1] adoption levels through the period ending in 2030. The GMP includes a five-year implementation plan, a ten-year roadmap, and a comprehensive benefit-cost analysis (BCA) for stakeholders to review and the PUC to approve for the purpose of allowing the Company to make grid modernization investment proposals in the future. As described below, the GMP expands significantly on the initial grid modernization plans submitted previously to the PUC under Docket 4770 and addresses input from stakeholders from the past two years.

The Company uses the term "grid modernization" to refer to those investments associated with managing the distribution system with more granularity to create a platform of solutions that enables more DER to connect while also giving customers more control over their energy decisions, reducing energy use, and improving reliability.[2] Grid modernization is not a single project or even program, but rather a long-term strategic initiative to meet the evolving expectations of customers safely and reliably.

Significant change is occurring across the energy industry due to changing customer behavior and expectations, including increased adoption of DERs like renewable distributed generation (DG), beneficial electrification (BE), and advanced "smart" technologies that can actively manage energy use in customers' homes and places of businesses. Adoption of these DER technologies is critical to enabling customer empowerment and meeting State clean energy goals. However, interconnecting them into the existing electric system infrastructure is becoming increasingly difficult and expensive. Rhode Island needs a well-coordinated and integrated grid modernization plan now in order to meet the unmet Operational, Customer, and Clean Energy needs summarized below.

Operational Needs: Operational needs include enabling cost-effective solutions for distribution system issues caused by customer DER adoption. These issues are localized today, but without grid modernization, they are expected to become systemic in 5-10 years. Grid modernization will enable the Company to cost-effectively address these system issues and provide customers and

[1] DER is defined here as a resource sited close to customers that can provide electricity generation (e.g., solar DG, wind DG) or flexible demand (e.g., energy storage, EVs, electric heat pumps).
[2] Energy savings here refers to savings in the future compared to no investment in grid modernization (e.g., without VVO/CVR or AMF customer energy insights). However, because the primary energy goal for Rhode Island is decarbonization, customers' overall energy use may increase in the future compared to today, as more EVs and electric heat pumps are adopted.

DER developers with better access to the electric distribution system compared to a future without grid modernization, including:

- Reduced DER Interconnection Costs: DER developers and customers will experience lower DER interconnection and other costs due to the ability of the Company to autonomously or remotely control power flows on the distribution system rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to interconnect DERs. Reducing interconnection costs is expected to result in fewer DER project applications being reduced in size or cancelled altogether.

- Improved DER Operation: DER developers and customers will be able to continue to operate DERs in the future without significant energy curtailment due to the ability of the Company to optimize DER load rather than relying on seasonal curtailment to maintain thermal and voltage compliance.[3] Reducing DER curtailment is expected to result in higher DER utilization that can support continued adoption of renewable DG and accelerated adoption of EVs and other DERs throughout the State.

- Improved DER Experience: Grid modernization investments enable improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes (e.g., flexible interconnection options, reductions in time to interconnect), and better customer and third-party information sharing and services.

In addition, a significant portion of the Company's current automated meter reading (AMR) technology is reaching the end of its design life and needs to be replaced. Details on this operational need are presented in the Updated AMF Business Case.

Customer Needs: Customers increasingly want more affordable, cleaner, and more reliable energy that they can manage and control. Grid modernization investments enable the Company to meet customers' evolving expectations by providing them with more energy savings opportunities, cleaner energy options, simpler and lower-cost DER interconnections, reliability improvements, and greater choice and control in addressing their energy needs compared to a future without grid modernization, including:

- Lower Energy Use: Customer will have more opportunities to reduce their energy use due to the ability of the Company to provide greater customer energy insights and control (see Greater Customer Control described below) and operate distribution feeders at lower overall voltages (within ANSI limits), which will reduce electricity consumption and peak demand from customer appliances.

[3] Seasonal curtailment means the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the system design limitations of the system.

- Cleaner Energy: Customers will have a smaller carbon footprint due to reduced energy use and increased utilization of renewable resources (see Lower Energy Use and Improved DER Operation described above).

- Affordable DER Adoption: Customers will have more affordable options to invest in their own DER technologies in areas where these technologies are most cost-effective due to the ability of the Company to reduce costs and other barriers to interconnect and operate DERs (see Reduced DER Interconnection Costs and Improved DER Experience described above).

- Improved Reliability: Customers will experience reduced outage restoration times due to the ability of the Company to more quickly locate and isolate a fault and restore power rather than waiting for customers to report outages and field crews to locate and restore power.

- Greater Customer Control: Customers will have better control over their energy bills with the ability to take action based on enhanced energy use insights, integrating AMF with in-home technologies, and responding to future pricing mechanisms like time-varying rates to reduce demand for energy during peak demand periods.

Clean Energy Needs: Rhode Island's clean energy needs include achieving ambitious clean energy goals based on the Resilient Rhode Island Act and Governor Raimondo's Executive Order 20-01, *Advancing a 100% Renewable Energy Future for Rhode Island by 2030*.[4] Grid modernization investments will help Rhode Island meet its clean energy goals by enabling greater customer energy savings and DER adoption. Enabling DER adoption, in particular renewable DG, EV, and EHP adoption, is a key driver for meeting the State's clean energy needs because it will enable customers to reduce their overall carbon footprint, including reducing transportation-related emissions that make up 40% of the State's carbon dioxide (CO_2) emissions.[5] Grid modernization investments will help reduce the costs and other barriers to interconnect new DERs in Rhode Island (see Reduced DER Interconnection Costs and Improved DER Experience described above), which will drive more DER adoption and investment in the State.

Without investments in grid modernization based on a well-coordinated and integrated GMP, distribution system infrastructure investments will continue to be piecemeal and not optimized in

[4] *See* Executive Order 20-01, *Advancing a 100% Renewable Energy Future for Rhode Island By 2030* (January 17, 2020); *See also* Resilient Rhode Island Act, R.I.G.L. § 42-6.2 (setting forth the state's clean energy goal to meet 80% greenhouse gas emissions reduction by 2050, referred to herein as the 80x50 Goal).
[5] *See* U.S. Energy Information Administration, 2017 Data, *Energy-Related CO_2 Emission Data Tables*, at Table 4 (State energy-related carbon dioxide emissions by sector) (Released May 20, 2020), https://www.eia.gov/environment/emissions/state/

a way that benefits all customers and meets the identified needs. In addition, the Company believes the electric distribution system will be a roadblock to achieving clean energy goals and the Company and State will be ill-prepared for the clean energy transition. If the Company takes a "do nothing" approach and does not invest in grid modernization, increasing interconnection cost will slow renewable DG adoption rates below the current level, EV charging infrastructure will be more costly, and customer participation in DER and Energy Efficiency programs will be limited. These consequences of a "do nothing" approach will put some of the State's ambitious clean energy goals out of reach.

Transforming Rhode Island's electric distribution system is a journey that will take time and that must be undertaken in a thoughtful and strategic manner. The Company believes that now is the right time to take the next concrete step in that journey to empower customers and meet the operational and clean energy needs of the next decade.

1. Introduction

1.1. <u>Docket No. 4770</u>

In November 2017, the Company submitted an application for approval of changes in electric and gas base distribution rates in Docket No. 4770 (2017 Rate Case),[6] along with a Power Sector Transformation (PST) Vision and Implementation Plan (PST Plan).[7] The PST Plan proposed a suite of investments, including grid modernization solutions and a state-wide deployment of Advanced Metering Functionality (AMF), to modernize the State's energy infrastructure. Following several months of discovery, testimony, and technical sessions before the PUC, the Company and the intervening parties filed an Amended Settlement Agreement (ASA) that resolved all disputed issues in both dockets, which the PUC approved at an Open Meeting on August 24, 2018.

The ASA included an initial, limited set of grid modernization investments as part of a three-year Multi-Year Rate Plan (MRP), and further required the Company to file a comprehensive Grid Modernization Plan (GMP) and Updated AMF Business Case, which describes how each integrates with the other and includes, among other requirements, a transparent, updated BCA that fully incorporates the Benefit-Cost Framework adopted by the PUC in its written Report and

[6] *See The Narragansett Elec. Co. d/b/a National Grid, Application for Approval of a Change in Elec. and Gas Base Distribution Rates,* Docket No. 4770 (November 27, 2017) [hereinafter the 2017 Rate Case].

[7] *See Id.*; *see also The Narragansett Elec. Co. d/b/a National Grid, Proposed Power Sector Transformation (PST) Vision and Implementation Plan*, Docket No. 4780 (November 28, 2017) (Following review of the filings, the PUC docketed the rate case and PST Plan filings separately.).

Order in Docket No. 4600[8] (Docket 4600 Framework) and the PUC's Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company d/b/a National Grid (Docket 4600 Guidance Document).[9] Table 1.1, below details how the GMP addresses each of the relevant grid modernization requirements within the ASA. Section 1.6 below discusses in more detail how the GMP aligns with the Docket 4600 goals.

[8] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates In Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 (July 31, 2017). .

[9] *See Pub Util. Comm'n Guidance on Goals, Principles and values for Matters Involving the Narragansett Elec. Co. d/b/a National Grid,* Docket 4600-A (October 27, 2017) [hereinafter Docket 4600 Guidance Document].

Table 1.1: Amended Settlement Agreement Terms Mapping to GMP Section

ASA Grid Modernization Terms	GMP Business Case or Other GMP Document Sections
Objectives for the electric grid to advance the Goals for the Energy System and Rate Design Principles, and potential visibility requirements of the benefit-cost framework in Docket 4600 Guidance Document	• Section 1.7: Alignment with Docket 4600 Goals
A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence	• Section 3: Risk Management Approach • Implementation Plan: all sections
Explanation of the role of currently active programs	• Section 4: Current Grid Modernization Activities
A plan and explanation for the integration and leveraging of customer-side technologies and resources in the near and long-term	• Section 4.3: Complimentary and Supporting Elements • Section 7: AMF Roadmap and Grid Modernization Integration
A description of how the GMP, in particular the distribution planning components, addresses the relationship between electrification of heating and transportation and energy efficiency to allow for the furtherance of overall reduced peak demand while also encouraging electrification of heating and transportation	• Section 3.2: Future State Scenarios • Section 4.3.2: Load Management Programs • Appendix – Section 4: Distribution Planning Process • Appendix – Section 5: Load Forecasting Details • Appendix – Section 7: Feeder-Level Analysis Details
Full assessment of the various initiatives being contemplated, including an explanation and evaluation of how the initiatives link to each other. The assessment will consider short and long-term initiatives to include active and future programs.	• Section 5: Planning Analysis and Recommendation • Implementation Plan: all sections
Functionalities to achieve [the] objectives	• Section 5.5: Functionality and Benefit Impacts Assessment • Appendix – Section 8: Functionality Definitions
Review of options for candidate technologies to deliver those functionalities	• Section 5: Planning Analysis and Recommendation • Implementation Plan: all sections • Updated AMF Business Case (separate filing)
An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments	• Implementation Plan: all sections
Investments and technology deployments planned through the end of any proposed AMF implementation	• Section 5.6: Proposed Solution Set • Section 5.7: 2030 Roadmap • Section 7: AMF Roadmap and Grid Mod Integration • Implementation Plan: all sections

ASA Grid Modernization Terms	GMP Business Case or Other GMP Document Sections
Implementation plans outlining the details and technologies over a five-year horizon plus an outline of how this plan aligns with the longer term (i.e., a ten-year roadmap). The GMP will provide a roadmap of potential investments beyond the term of the current multi-rate plan (MRP); requests to fund those investments will be included as part of a general rate case, MRP, or ISR Plan filings.	• Section 5.7: 2030 Roadmap • Implementation Plan: all sections
Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities	• Implementation Plan – Section 11: Operational Telecommunications • Appendix – Section 9: OpTel Strategy Details
Explanation of congruency with grid modernization activities in New York and Massachusetts	• Section 1.8: Alignment with National Grid Jurisdictions
Transparent, updated benefit cost analyses that fully incorporate the Docket 4600 framework	• Section 8: BCA Evaluation Under Docket 4600 • Appendix – Section 11: Benefit Cost Analysis Details

In addition, the ASA required the Company to engage with stakeholders via a newly created PST Advisory Group to develop the GMP and Updated AMF Business Case. Through the PST Advisory Group, the Company formed a GMP and AMF Subcommittee that launched in October 2018. The GMP and AMF Subcommittee has engaged with the Company over the course of numerous meetings between October 2018-October 2020 and has provided valuable input to the development of the GMP and the Updated AMF Business Case. Details about this collaboration can be found in the AMF Business Case filing under *Section 2.1: PST Advisory Group GMP and AMF Subcommittee Engagement*.

1.2. GMP Approach

The Company is actively engaged in shaping grid modernization activities within the industry. Employees regularly participate in and take leadership roles in Institute of Electrical and Electronics Engineers (IEEE) working groups and standards committees, National Electric Code (NEC) committees, Electric Power Research Institute (EPRI) research programs and advisory councils, The Centre for Energy Advancement through Technological Innovation (CEATI) interest groups and taskforces, the U.S. Department of Energy (DOE) advisory group concerning the Next-Generation Distribution System Platform (DSPx) Modern Distribution Grid guidelines,[10] and Rhode Island PST stakeholder engagements. The Company leveraged this

[10] DOE's Modern Grid Initiative works with public and private partners to develop the concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future. Multi-volume guidance documents are available on the Pacific Northwest Laboratory's website, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

experience and selected best practices to develop a systematic approach to evaluating grid modernization investments including their costs and benefits to Rhode Island.
The intent of the GMP is to efficiently leverage the functionalities of updated technologies, new programs, and services to meet evolving customer needs. To accomplish this and select a set of grid modernization solutions that will meet Rhode Island's needs through 2030, the Company followed the stepwise approach outlined in Figure 1.1.

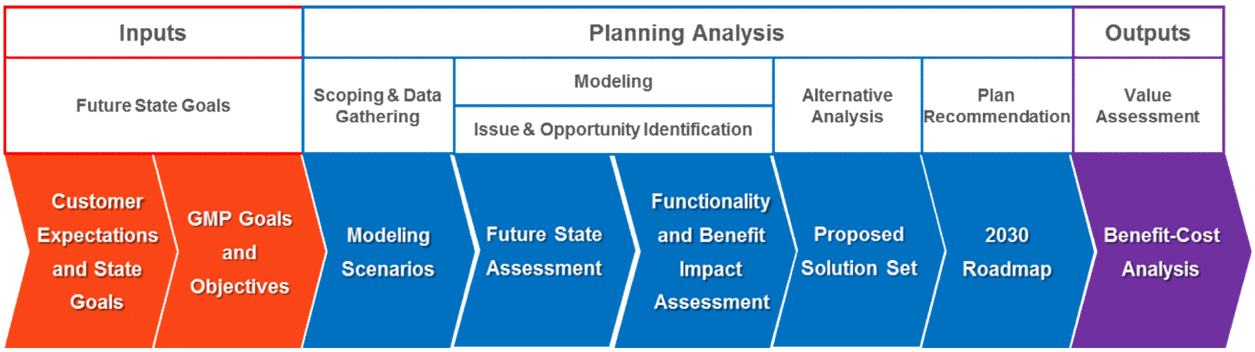

Figure 1.1: Illustration of GMP Solution Assessment Approach

This approach and the 10-year (2030) roadmap are discussed in detail in Section 5 of this GMP Business Case.

1.3. Benefit Cost Analysis

The Company developed a detailed BCA, which compared the grid modernization investments envisioned out to 2030 to a "reference case" with no grid modernization investments (i.e., traditional investments only). The Company's GMP BCA is consistent with the Docket 4600 Framework, and is discussed in detail in *Section 8: BCA Evaluation Under Docket No. 4600*. This BCA is one of the few grid modernization filings to perform a full quantitative BCA specifically on grid modernization investments, including a "Grid Modernization Only Case" that excludes costs and benefits due to AMF.[11] To ensure a comprehensive BCA that covers all potential benefits and costs introduced by grid modernization, the Company engaged with a wide variety of subject matter experts both within and external to the Company (e.g., PST Advisory Group), reviewed and participated in industry and government forums, and surveyed several other utility filings to understand the scope of the purported grid modernization benefits.

Through this engagement and research, the Company was able to quantify a number of important grid modernization benefits and costs, and when quantification was not possible, the Company

[11] Dayton Power & Light filed its Distribution Modernization Plan with the PUC of Ohio in December 2018 and included a full BCA for both its GMP and AMF filings, but the scope of the benefit assessment differs from the Company's assessment. Xcel Energy filed its Integrated Distribution Plan with the PUC of Minnesota November 2019 and included a full BCA for component technologies. Other filings have focused primarily on AMF benefits and costs. Details are provided in Attachment B, the Appendix.

included a discussion of qualitative benefits. The Company quantified many of the benefits resulting from grid modernization investments using detailed state-wide and feeder-level modeling of the 2030 future state scenarios and well-established BCA methodologies and input assumptions. This qualitative analysis is discussed more fully in *Section 8.6: Qualitative Assessment*.

1.4. Accountability

National Grid is committed to delivering on grid modernization investments. There are several uncertainties associated with the evolution of the grid that are out of National Grid's control, including the actual pace of DER penetration over time and the corresponding system impacts as determined through on-going distribution planning processes, the evolution of complementary policies and programs, and the state of grid modernization implementation; however, the Company has created several external and internal measures that will hold it accountable to what is within its control.

The GMP Roadmap is intended to guide the development of future investment plans, but not lock them in since the form and function of the distribution system is evolving and is expected to change significantly over the period of the GMP. In addition to the GMP Roadmap, the Company fully expects to adapt and adjust its plans considering the many metrics presented in *Section 6.2: Reporting Metrics*. These metrics will be reported annually throughout the horizon of the GMP to ensure the timely and effective deployment of solutions and realization of benefits. Project plans for future investments will be presented in their appropriate forums at the appropriate time throughout the horizon of the GMP. This iterative process enables on-going engagement and review and reduces risks.

1.5. Value for Rhode Island

The value of the proposed grid modernization investments for Rhode Island is captured in both the quantitative and qualitative components of the BCA. Quantified net benefits are estimated to be between $250-$932 million (20-year NPV) depending on customer DER adoption, assuming the full suite of grid modernization investments is made, including full deployment of AMF.

Figure 1.4 summarizes the results of the BCA for two grid modernization deployment cases - grid modernization only without AMF (Grid Mod Only Case)[12] and full grid modernization with AMF (Full Grid Mod Case)[13] and two future state scenarios representing the low and high

[12] Grid Mod Only case assumes grid modernization solutions (e.g., smart controllers, DER optimization using active power control) excluding AMF are used to integrate DG and better accommodate BE.

[13] Full Grid Mod Case assumes grid modernization solutions including AMF with TVR are used to integrate both DG and BE (e.g., EV charging optimization using load shifting), enable increased customer choice and control, and provide a better customer experience.

customer DER adoption forecasts (i.e., Low DER and High DER). For a given scenario, benefits of both grid modernization cases (i.e., Grid Mod Only or Full Grid Mod) were estimated based on a comparison to a "reference case", which assumed traditional infrastructure investments – without grid modernization.[14] Descriptions and detailed results for each case and scenario are presented in *Section 7: BCA Evaluation Under Docket 4600* of the GMP Business Case.

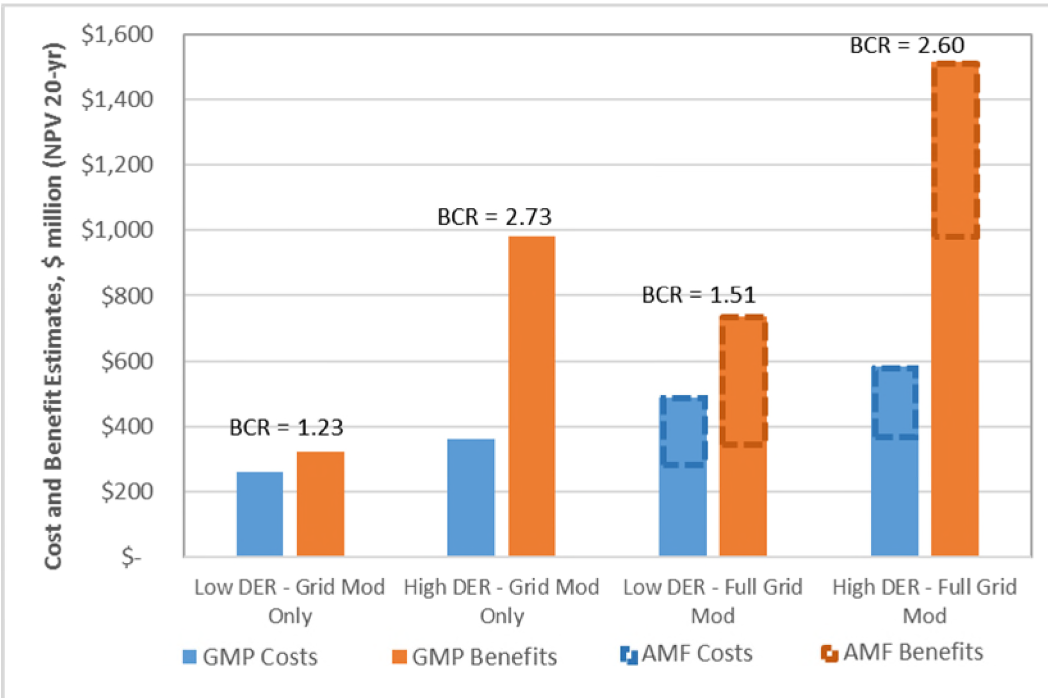

Figure 1.4: Summary of BCA Estimates for all Grid Modernization Cases and DER Adoption Scenarios[15]

The quantitative BCA results in hundreds of millions of dollars in net benefits for Rhode Island customers on a 20-year NPV basis. Benefits exceed costs for all four alternatives and all benefit-to-cost ratios (BCR) are well above one. Additional economic development, regional, and qualitative benefits evaluated and described in the GMP Business Case would add to the quantified value.

BCA results also indicate that the proposed GMP benefits are significantly enhanced with AMF, particularly in the Low DER adoption scenario where benefits are driven primarily by customer energy savings. AMF benefits are much less dependent on the DER adoption scenario than the benefits of the Grid Mod Only Case.

[14] Note that the BCA does not attempt to compare the benefits and costs of a future state to today's current state, instead it compares only the benefits and costs of a future Grid Modernization Case compared to a future Reference Case without grid modernization.
[15] The Full Grid Mod Case results are based on the AMF benefits and costs for the AMF "base case" (i.e., Opt Out, Mid Results, RI+NY Deployment) option. Details are provided in the Updated AMF Business Case filing.

1.6. GMP Filing Overview

The GMP consists of four documents: (1) this GMP Business Case, which explains the need, value, and accountability for grid modernization investments, as well as a solutions assessment roadmap and BCA based on the PUC's Docket No. 4600 Framework; (2) the Implementation Plan as Attachment A, which explains how grid modernization will be implemented over the next five years; (3) an Appendix as Attachment B, which includes technical and planning details that support the GMP Business Case and Implementation Plan; and (4) the confidential BCA Model, as Attachment C. The GMP significantly expands on the initial grid modernization plans provided in Docket No. 4770 and addresses input from the past two years from the GMP and AMF PST Subcommittee stakeholders.

The scope of the GMP focuses on the distribution planning and operations-related investments that the Company needs or will need to effectively and efficiently manage more dynamic loading of the grid in a safe, reliable and cost-effective fashion. It should be noted that the GMP does not represent the Company's entire capital plan nor does it cover the full range of innovative efforts occurring across the Company. In addition, the GMP only addresses the electric distribution needs in Rhode Island. Although grid modernization can benefit the State's and region's overall energy system, including the electric transmission system, bulk generation, and even the States' heating and transportation sectors, the investments needed to modernize the other parts of overall energy system are outside of the scope of this GMP.

A major investment in the GMP is AMF; therefore, the GMP highlights key areas of AMF and GMP integration. For example, the Implementation Plan provides a summary of the AMF proposal, and Section 7 of the GMP Business Case highlights how AMF integrates with GMP capabilities to empower customers with greater control of their energy usage and supports more efficient operation of the distribution system. In addition, the Company is filing the Updated AMF Business Case in accordance with the ASA, concurrently with the GMP, for the PUC's review and approval. The Updated AMF Business Case seeks recovery of costs for full deployment of AMF and provides detailed information concerning the need, value, and accountability for AMF investments, including a separate comprehensive BCA for the incremental AMF-related costs and benefits.

The Company is not seeking cost recovery for any other grid modernization solutions as part of this GMP filing. Instead, such requests for cost recovery will be presented to the PUC for review via future filings in existing forums such as the Infrastructure, Safety, and Reliability (ISR) Plans and general rate case filings.

1.7. Alignment with Docket No. 4600 Goals

The PUC's Docket No. 4600 Guidance Document specifies that any proponent of a program proposal with associated cost recovery will need to meet the Docket No. 4600 goals, principles, and framework.[16] While this GMP is not seeking cost recovery at this time, the Company has still provided an explanation of how the GMP advances, detracts from, or is neutral to each of the goals for the "new" electric system, as outlined in Docket No. 4600, in Table 1.2.

[16] Docket 4600 Guidance Document, *supra* note 9 at 2.

Table 1.2: Alignment of GMP Investments with Docket No. 4600 Goals

Goals For "New" Electric System	Advances? / Detracts From? /Is Neutral To?
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 GMP investments are foundational enablers necessary to efficiently and cost-effectively manage two-way power flows in a reliable, safe, clean, and affordable manner. The GMP's top priority is to ensure the electric distribution grid continues to operate within compliance of planning criteria and service quality standards, but also to leverage opportunities to optimize performance to enhance customer benefits where they are cost effective. Specifically, GMP investments can reduce customer energy use and distribution system capacity requirements directly though voltage optimization and conservation control schemes (i.e., VVO/CVR), which enables the operation of distribution feeders at lower overall voltages to reduce electricity consumption and peak demand from customer appliances. AMF can contribute to incremental benefits in this area by integrating granular AMF voltage data into VVO/CVR control schemes. In addition, AMF will enable customers to become more active in managing and reducing their energy usage through enhanced energy use insights (e.g., AMF-based High Bill Alerts) or integrating AMF with in-home technologies. GMP investments will also avoid multiple utility costs, thereby creating the possibility of improved affordability for Rhode Island customers, including better management of: • Distribution system O&M costs • Distribution system infrastructure capital costs • Transmission system infrastructure capital costs • Bulk energy purchases In addition, GMP investments can reduce customer outage restoration times through the addition of advanced reclosers, breakers, and fault location, interruption, and service restoration (FLISR) control schemes. AMF has the potential to increase reliability further by enabling better outage management and reduced outage notification times due to autonomous meter outage notifications, which allow field personnel to restore power more quickly without relying on customer calls and substation monitoring.
Strengthen the Rhode Island economy, support economic competitiveness, and retain and create jobs by optimizing the benefits of a modern grid and attaining	Advances: The GMP investments will help more Rhode Island customers reduce their energy costs and earn additional revenue by enabling them to invest in their own DER technologies in areas that are most cost-effective for these resources. In addition, GMP construction spending will create additional jobs in Rhode Island. Indirectly, GMP impacts are felt in the local supply chain, since industries are providing goods and services for the GMP implementation. Induced impacts are felt mainly in the local service sector, such as increased retail activity and hiring as the direct and indirect workers spend a portion of their incomes locally.[17]

[17] Full economic development impacts assessment is presented in the Appendix document.

Goals For "New" Electric System	Advances? / Detracts From? /Is Neutral To?
appropriate rate design structures	
Address the challenge of climate change and other forms of pollution	<u>Advances</u>: GMP investments will reduce greenhouse gases (GHGs) and other harmful emissions by enabling reduced energy use (e.g., VVO/CVR, High Bill Alerts) and renewable DG curtailment. The investments will also enable more cost-effective interconnection and better utilization of clean DERs (e.g., solar DG, EVs, EHPs) into the electric distribution grid, which will reduce Rhode Island's reliance on more carbon-intensive energy technologies. Finally, additional emissions reductions will be realized due to a reduction in utility "truck rolls" resulting from improvements in operational efficiency.
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	<u>Advances</u>: Grid modernization investments can reduce DER interconnection costs and enable improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes, flexible interconnection options, reductions in time to interconnect, and better customer and third-party information sharing and services. By reducing costs and other barriers to interconnect, grid modernization will help more Rhode Island customers invest in their own DER technologies in areas where these technologies are most cost-effective. In addition, AMF will provide more granular energy usage data to enable customers to better understand and choose among DER offerings (i.e., DG, storage, EV, DR, and Energy Efficiency solutions) to better manage their energy usage and costs. Specifically, GMP investments will facilitate cost-effective customer investment in DERs by enabling: • Load optimization to relieve thermal or voltage constraints due to DER adoption rather than relying on traditional "wires-based solutions" • Improved efficacy of Energy Efficiency and DR programs by providing more granular data to customers (e.g., detailed billed energy use, in-home displays) • Third-party programs and offerings that will drive innovation and provide additional value to customers, while encouraging new industry participants to enter the market with new customer offerings • Savings on EV charging costs by virtue of future time-varying pricing that incentivize customers to displace EV charging to off-peak times • Higher hosting capacity on the distribution system to accommodate higher penetrations of DERs at lower cost • More cost-effective DER investment due to system information sharing via the System Data Portal In the future, a distributed energy resource management system (DERMS), in combination with an Advanced Distribution Management System (ADMS) and other GMP investments, will enable optimization of DER output (e.g., reduced DER curtailment) and

Goals For "New" Electric System	Advances? / Detracts From? /Is Neutral To?
	provide the necessary information, operations and settlement services to DER providers, which are required to efficiently integrate DER into the distribution system.
Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society	Advances: The GMP investments are necessary to assess the locational and temporal value DER may provide to the electric system. In the near-term, grid modernization will help identify and fairly compensate non-wires alternative (NWA) projects. In the longer term, grid modernization, combined with new DG tariffs and TVR enabled by AMF, could more directly and accurately compensate DERs for their value.
Appropriately charge customers for the cost they impose on the grid	Advances: The GMP does not propose utility revenue requirements, cost allocation or rate design at this time. However, per the ASA, the Updated AMF Business Case includes assumptions to develop a future time varying rate proposal. AMF, in combination with time varying rates and other GMP investments, will enable new pricing and allocation mechanisms to attribute costs more equitably.
Appropriately compensate the distribution utility for the services it provides	Advances: The ability to monitor two-way power flows will allow the Company to better understand the impacts of DER and assess the value that the grid provides to both consumers (i.e., rate payers) and producers (i.e., DER customers) and with this enhanced understanding the Company should be better positioned to develop innovative and appropriate rates.
Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive	Advances: The GMP includes a detailed BCA that is aligned with the Docket No. 4600 regulatory framework in order to better align distribution utility, customer, and policy objectives. In addition, specific GMP investments like the System Data Portal will provide transparency concerning system needs and opportunities for interested stakeholders, thereby fostering a more collaborative approach to distribution system planning and operations. AMF provides improved customer data access through the Customer Energy Management Platform (CEMP) and Home Area Network (HAN), as well as facilitating easier data sharing among customers and third parties using Green Button Connect (GBC).[18] It also enhances existing customer programs in EE, DR, and EVs as outlined in the Updated AMF Business Case and its Customer Engagement Plan. When coupled with future rate designs and incentives, AMF also aligns customer and utility interests with policy objectives by providing customers with greater choice and control over energy usage while providing the Company with better visibility of its distribution system, leading to a cleaner, more efficient electric distribution grid. Finally, stakeholder engagement has been a large component of the GMP and AMF filings and through this forum, the Company and stakeholders have worked to ensure customer and policy objectives and interests are addressed. Through this GMP, the Updated AMF Business Case, and future regulatory filings, the Company will continue to align grid modernization with customer, distribution utility, and policy objectives and interests.

[18] Descriptions and other details about CEMP and GBC are presented in the Implementation Plan and the Updated AMF Business Case.

Through discussions with the GMP and AMF Subcommittee, a need was identified to address goals that are not only grid facing, but also customer facing. Docket No. 4600 identifies the following customer-facing goals:

- Empower customers to manage their costs
- Customer education and engagement programs to provide all customers with the information and tools to optimize their electricity consumption
- Provide opportunities to reduce energy burden

The GMP investments, particularly investments in AMF, advance these goals as well. For example, AMF's advanced pricing capability will allow customers to manage their costs by enabling new pricing mechanisms that attribute costs and benefits more equitably, and AMF's Customer Engagement Plan (CEP) presents how the company will engage, educate and empower customers to understand and realize the benefits of AMF, including the choices available to them. As part of the CEP, AMF's Customer Energy Management Platform (CEMP) will provide increased information and tools so customers can understand and optimize their electricity consumption. Details are presented in the Updated AMF Business Case filing.

1.8. Alignment with National Grid Jurisdictions

The Company and its affiliates operate distribution systems in Rhode Island, Massachusetts and New York. Grid modernization plans have been presented in regulatory forums in each of these jurisdictions. While there are differences in prioritization that may impact the timing of implementation in each jurisdiction, the jurisdictions share the same vision and roadmap for grid modernization. Therefore, opportunities exist to leverage synergies that will support multiple jurisdictions. The Control Center and Back Office investments presented in *Section 5.7: 2030 Roadmap* provide the greatest opportunity for synergies, including investments in Geographic Information System (GIS) Data Enhancements, Advanced Distribution Management System (ADMS) Core Functionality, Underlying Information Technology (IT) Infrastructure, and Appropriate Cyber Services. Consequently, the deployment of certain solutions in the GMP would be performed through the National Grid USA Service Company so that costs can be shared and equitably allocated to all affiliated operating companies that utilize the solution.

On May 10, 2018, the Massachusetts Department of Public Utilities (DPU) approved certain grid facing elements of the Massachusetts Electric Grid Modernization Plan and deferred authorization of the Massachusetts Electric AMF Plan. In doing so, the DPU stated that it believes AMF is an important element within grid modernization; however, it would seek further details on the relative costs and benefits through a future proceeding. In response to the terms of the regulatory approval, the Company's Massachusetts affiliates are currently progressing the following grid modernization elements: feeder monitoring sensors, advanced grid devices to enable VVO and FLISR, ADMS/SCADA, and communications and information/operational technologies (i.e., underlying IT infrastructure, appropriate cyber services, and telecommunications network management).

On July 2, 2020, the DPU opened an investigation on customer facing grid modernization elements, focused on whether "targeted deployment of advanced metering functionality to electric vehicle (EV) customers" will yield benefits that justify the costs. The DPU solicited comments on eight questions from the Massachusetts electric distribution companies and other stakeholders. The Company filed comments on August 13, 2020 and reply comments on September 4, 2020. As part of the investigation, the DPU hosted four technical conferences, addressing issues related to the status of existing meters, trends in meter deployment, AMI meter functionality, back-office systems, TVR, municipal aggregation, and AMI opt-out provisions.[19] The Massachusetts docket is open, and the Company's Massachusetts affiliates remain committed to working with the DPU as part of the process to further refine and advance their AMF/AMI proposals.

On March 15, 2018, the New York Public Service Commission (PSC) approved a rate case settlement agreement that included several grid modernization elements and required the development of a revised AMF business case to be filed with the PSC on a later date. In response to the terms of the settlement agreement, the Company's upstate New York affiliates are progressing the following grid modernization elements: feeder monitoring sensors, advanced grid devices to enable VVO (FLISR was deferred until after 2021), ADMS, underlying IT infrastructure, appropriate cyber services, and telecommunications. In addition, a revised business case for AMF deployment in upstate New York was submitted to the PSC on November 15, 2018. In November 2020, the PSC issued two orders approving plans to deploy approximately 3 million electric AMI meters and 1.24 million AMI-enabled gas modules across Upstate New York. Additional details on this approval can be found in the Updated AMF Business Case. The Company filed a new rate case on July 31, 2020 with a plan that includes proposals to further progress the previously approved grid modernization investments and expand with additional grid modernization investments including FLISR.

In addition to the Company's efforts in Rhode Island and our affiliates' work in other jurisdictions, the Company is actively engaged in shaping grid modernization activities within the industry more broadly. Employees regularly participate in and take leadership roles in PST stakeholder engagements, Institute of Electrical and Electronics Engineers (IEEE) working groups and standards committees, National Electric Code (NEC) committees, Electric Power

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[19] *See Investigation by the Dep't of Pub. Util. on its own Motion into the Modernization of the Elec. Grid – Phase II,* Docket D.P.U. 20-69 [hereinafter MA Grid Mod Phase II Investigation], Memorandum Regarding Agenda for November 17, 2020 and November 20, 2020 Technical Conferences (November 4, 2020); *see also* MA Grid Mod Phase II Investigation, Memorandum Regarding Agenda and Registration Links for December 3, 2020, and December 4, 2020 Technical Conferences (November 25, 2020).

Research Institute (EPRI) research programs and advisory councils, The Centre for Energy Advancement through Technological Innovation (CEATI) interest groups and taskforces, and the U.S. Department of Energy (DOE) advisory group concerning the Next-Generation Distribution System Platform (DSPx) Modern Distribution Grid guidelines.[20]

1.9. Efforts in Other States

According to the DOE, today's electric grid lacks "the attributes necessary to meet the demands of the 21st century and beyond."[21] Grid modernization, then, would refer to any and all efforts to bring the electric grid into alignment with current and future needs. While the term has been used to encompass a broad array of initiatives, common themes include improving the grid's responsiveness, interactivity, and resilience.[22] Drivers of grid modernization across the country include emerging technologies, evolving consumer demands, cyber security concerns, extreme weather events, and a broadly shared desire – among utilities, regulators, policy makers, and the public – to reduce the GHG emissions associated with electricity production and support the development of low-carbon energy infrastructure.

Interest in grid modernization among utilities and utility regulators has increased in recent years. Because it involves identifying and prioritizing a suite of near-term investments in new and emerging technologies to enable unprecedented capabilities in an uncertain future, grid modernization is among the most complex challenges that utilities, regulators, and stakeholders grapple with today. Consequently, the Company's efforts to address grid modernization in Rhode Island, and the leadership shown by the Rhode Island PUC in this area, are of national interest and significance.

A summary of notable recent grid modernization developments in other states is presented in Attachment B, the Appendix. As the summary shows, grid modernization is a complex, wide-ranging issue (or set of issues) that utilities and commissions have approached in different ways across the United States. Common themes of successful efforts include: the establishment of a strong value proposition; a gradual, phased approach; a clear vision for proposed investments, expressed in a detailed roadmap; robust stakeholder engagement; and utility accountability for delivering results.

[20] DOE's Modern Grid Initiative works with public and private partners to develop the concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future. Multi-volume guidance documents are available on the Pacific Northwest Laboratory's website, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

[21] https://www.energy.gov/grid-modernization-initiative

[22] https://nccleantech.ncsu.edu/wp-content/uploads/2019/05/Q12019_gridmod_exec_final.pdf

1.10. Grid Modernization Platform

The Company has leveraged the DOE DSPx guidance documents in creating its implementation plan and roadmap. The grid modernization technology options considered in the GMP consist of many of the "Core Components" and "Modular Optimizing Applications" presented in DOE's Modern Grid Initiative. The Modern Grid Initiative describes Core Components as the essential technologies that provide a foundation for a modern distribution grid. The Core Components create a base of functionalities necessary for a smarter grid (i.e., data acquisition, monitoring and control, system modeling and analytics) that enables the Company to more effectively manage the grid to maintain safe and reliable service. The Core Components will also support additional functionalities from Modular Optimizing Applications that will bring long-term value to customers including customer enablement and grid optimization by more effectively managing utilization of the grid through enhanced engagement with customers and DER providers.

The GMP proposed here presents the Core Components as a portfolio of foundational grid modernization investments that should be evaluated as a whole. Figure 1.1 below conceptually illustrates the Core Component layers and the Modular Optimizing Application elements that represent a modern distribution grid. The figure has been adapted from a figure in the DOE Modern Grid Initiative to show those elements being progressed by this GMP.

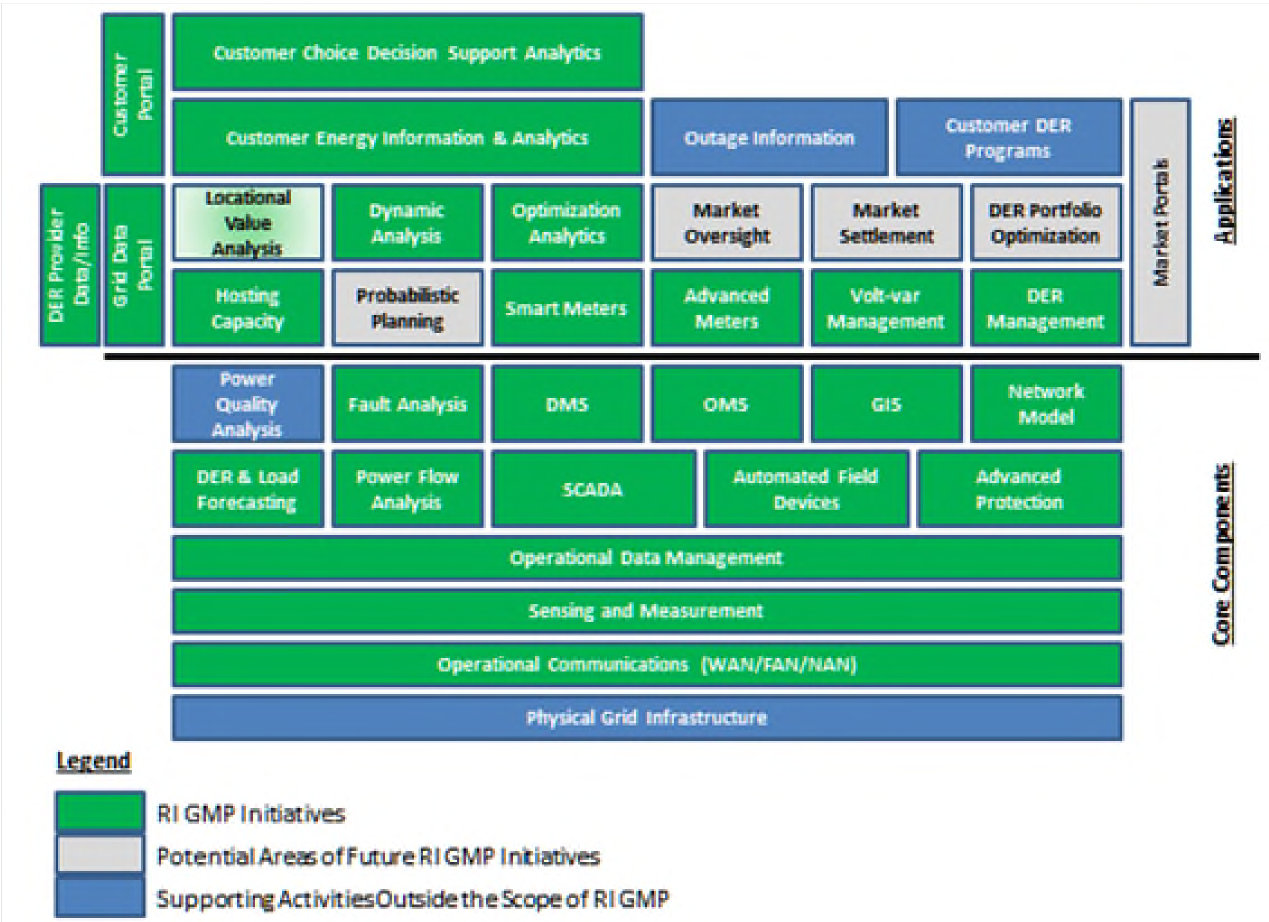

Figure 1.1: Grid Modernization Platform for Rhode Island

2. Today's Grid

2.1. Background

Across the U.S. and globally, the energy landscape is changing. As technology advances and customers have greater opportunity to manage their energy needs through personalized load management and adoption of renewable DG, EVs, and electric heat pumps (EHPs), demands on the grid are becoming more dynamic and less predictable. Utilities and stakeholders often reference this as a shift from one-way flow of electricity and information, moving from the utility to the customer, to two-way flow of electricity and information.

In Rhode Island, programs such as the Renewable Energy Growth (REG) Program and evolving customer expectations due to the continual and rapid digitization of customer information have changed the one-way power system paradigm.[23] Customers can now export electricity back to the grid and, if eligible, participate in net energy metering (NEM) or REG programs, and many are beginning to expect their "smart appliances" or "smart homes" to be able to communicate with the utility so they can better manage their energy use. Therefore, the Company believes it is not possible to continue with the status quo. Rhode Island needs to invest in grid modernization and other smart energy infrastructure that will improve customer satisfaction, support positive local economic impacts within Rhode Island[24] and create a more resilient, flexible, and agile energy grid.

The Company is seeing dramatic increases in renewable DG applications, particularly solar DG. Figures 2.1 and 2.2 show the increasing trends in the number of renewable distributed generation (DG) applications and megawatts (MW) of capacity interconnected in Rhode Island over the past ten years. In calendar year 2019 alone, the Company interconnected over 100 MW of DG, which was a 24 MW (31%) increase over 2018 and a 66 MW (192%) increase over 2017.

[23] Digitization refers to investment and installation of additional grid sensors and two-way communicating devices, including smart meters, requires a substantial investment in underlying telecommunications, operational data management, system performance modeling and evaluation tools, and both underlying physical and cyber security. As such, a core component of the modern distribution grid is the management of and interaction with an increasing volume and diversity of data – illustrating the vital importance in how we gather, transmit, and store data within and across our systems.

[24] Net economic impacts were estimated using the REMI regional economic model of the Rhode Island economy. Details of the analysis are included in Attachment B, the Appendix.

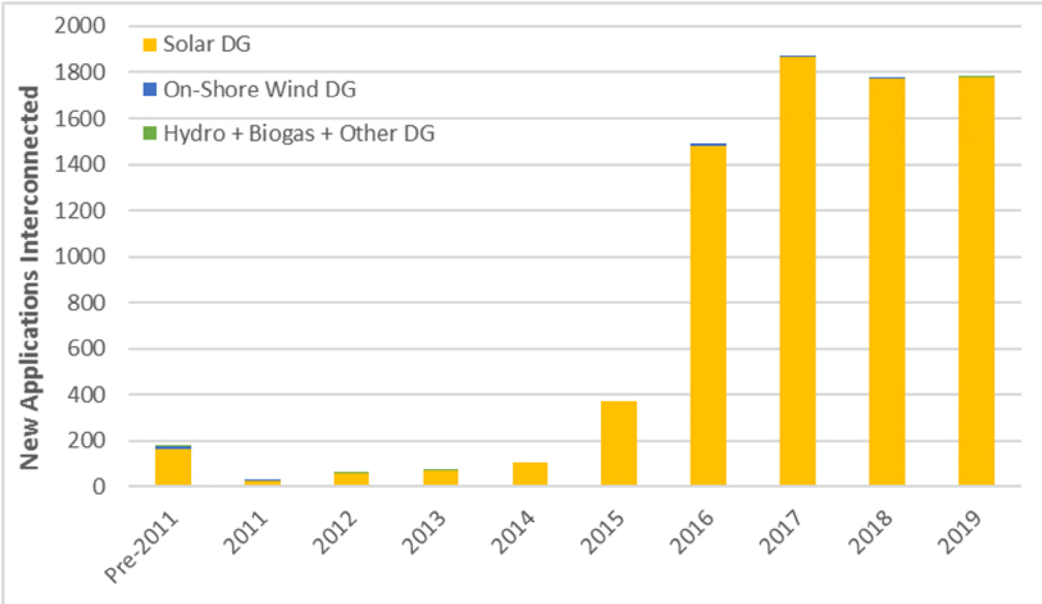

Figure 2.1: New DG Applications Interconnected Through December 2019

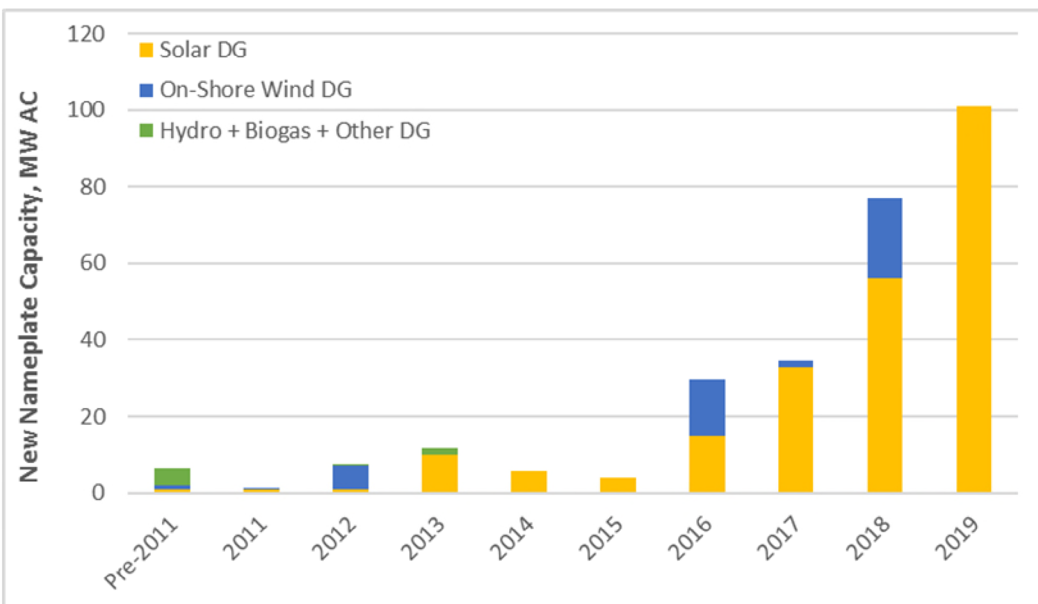

Figure 2.2: New DG Nameplate Capacity Interconnected Through December 2019

In addition, the Company currently has about 777 MW of DG projects in queue (i.e., "pending"), with 60% at the initial stages of the interconnection application process and 40% in the final stages.[25] Assuming a historic interconnection rate of between 30-45%, there would be an additional 230-350 MW interconnected likely within the next 1-3 years. The uptick has been attributed in part to an expansion of the Public Entity definition for remote net metering in Rhode Island. A continuation of renewable and DG incentive programs in Rhode Island coupled with the existing Federal Investment Tax Credit are expected to continue to drive application volumes for at least the next 3-5 years.

The Company is also seeing dramatic increases in the size of larger "complex" applications as third-party developers attempt to realize greater economies of scale and pursue Rhode Island's Community Solar incentive programs. On average, solar DG projects interconnected in 2019 were essentially 5 times larger in size (MW nameplate) than in 2016, and in fact, the Company is currently studying multiple DG projects in excess of 20 MW in Rhode Island.

Rhode Island needs grid modernization investments now in order to meet the three categories of unmet need described in the subsections below: operational, customer, and clean energy. Without a well-coordinated and integrated GMP, distribution system infrastructure investments would be made in an uncoordinated manner, rather than holistically through a comprehensive set of feeder level investments that provide the highest overall net benefits for energy savings, DER integration, and reliability, and not optimized in a way that benefits all customers and meets the identified needs. Transforming Rhode Island's electric distribution system is a journey that will take time and that must be undertaken in a thoughtful and strategic manner. It is important to take the next concrete step in the journey now to ensure that the electric grid does not hinder customer empowerment or achievement of clean energy goals and does not create higher costs in the long run.

2.2. Operational Needs

Unmet operational needs include enabling cost-effective solutions for distribution system issues caused by customer DER adoption. These issues are localized today, but without grid modernization, they are expected to become systemic in 5-10 years. Grid modernization will enable the Company to cost-effectively address these system issues and provide customers and DER developers with better access to the electric distribution system compared to a future without grid modernization, including:

- Reduced DER Interconnection Cost: DER developers and customers will experience lower DER interconnection and other costs resulting in fewer DER project applications being reduced in size or cancelled altogether

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[25] Final stages of the interconnection application include those in Conditional Approval, Design, Construction, and Meter Installation stages.

- Improved DER Operation: DER developers and customers will be able to continue to operate DERs in the future without significant energy curtailment resulting in higher DER utilization that can support continued adoption of renewable DG and accelerated adoption of EVs and other DERs throughout the State

- Improved DER Experience: Grid modernization investments enable improved customer DER experience (e.g., better DER location selection, streamlined DER interconnection processes, better customer and third-party information sharing and services)

In addition, the Company's current AMR meter fleet is reaching the end of its design life and needs to be replaced. Details on this operational need are presented in the Updated AMF Business Case.

The subsections below summarize some of the many operational issues resulting in the need for grid modernization.

2.2.1. Interconnection Issues

Over the last few years, Rhode Island has seen a large increase in the number of applications for solar DG, low but increasing levels of EV and EHP adoption, and broader participation and interest in opportunities to lower electric bills and/or take advantage of new revenue streams. However, some of the challenges associated with interconnecting DERs are increasing. Receiving local permitting approval, getting proper financing in place, and high site costs (including utility system upgrades to interconnect) are all risks associated with DER projects. Currently, due to these and other issues, between 50-70% of DG applications are cancelled prior to completing the project. The high saturation of current and proposed DERs being seen in Rhode Island today, and the need for additional distribution capacity to accommodate these higher levels of DER proposals, has prompted transmission level studies under the ISO-NE requirements which add time, and, in many cases, costs to this process.

Exacerbating many of these issues is the fact that the electric systems serving the areas with the most potential for DG development Rhode Island are areas designed to serve small amounts of load for one-way power flow. Generally speaking, the Company is seeing a high level of DG aggregation in rural areas where there is available land, but the electrical systems in these rural areas often do not have the available hosting capacity and are not robust enough to interconnect larger DG sites that introduce multi-directional power flow. Issues resulting from DER interconnections in these areas often include voltage, power quality, and protection coordination. System modifications including substation modifications, line reconductoring, advanced control and monitoring, and advanced protection schemes are required to maintain compliance obligations. Substation and distribution line and equipment upgrade, and modification investments can be in the multi-millions of dollars and take in excess of 12 – 24 months to execute.

As a result of the increasing demand for DG interconnections, the existing hosting capacity on many feeders in Rhode Island has decreased dramatically. Figure 2.3 shows the level of DG that would be able to be interconnected on all 3-phase feeders in Rhode Island without requiring significant distribution system upgrades.[26] This hosting capacity map was generated using the Rhode Island System Data portal and includes only the currently interconnected DG in the state. As can be seen, most feeders west of the State, and pockets in the south and east of the State, have less than 300 kW of hosting capacity left. The situation is much worse when the pending DG applications are included.

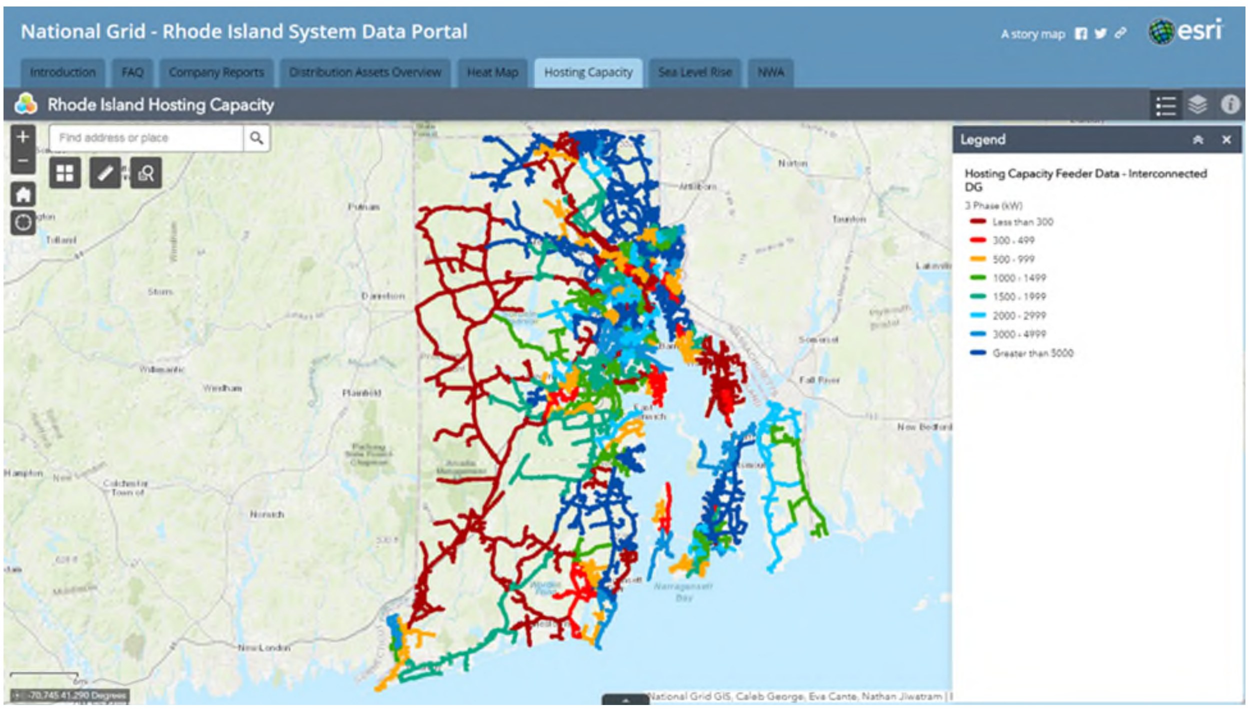

Figure 2.3: Rhode Island System Data Portal Hosting Capacity Map

This lack of hosting capacity throughout much of Rhode Island means that costly system upgrades will be necessary for interconnecting most new DG projects. As a result, interconnection costs have increased dramatically over the last few years for both smaller-scale and large-scale DG projects. Figure 2.4 summarizes the interconnection costs tracked by the Company for proposed DG projects in the last four and a half years. As can be seen, interconnection costs have recently increased over 440% for smaller DG projects (<1 MW) and 790% for large DG projects (>1 MW) since 2015. DG interconnection costs in Rhode Island are expected to rise even more substantially in the future. Cost estimates from the Western Massachusetts Study by the Company's affiliate in Massachusetts, which has seen even more

[26] Three-phase feeders are all feeders with 3 wires to accommodate 3-phase power. 3-phase feeders are typically mainline feeders but can also include side taps (past fuses), which would typically not be mainline.

rapid solar DG growth than Rhode Island, have resulted in DG project interconnection costs of over $2,000/kW on average, and some interconnection costs are over $5,000/kW, due to DG saturation.

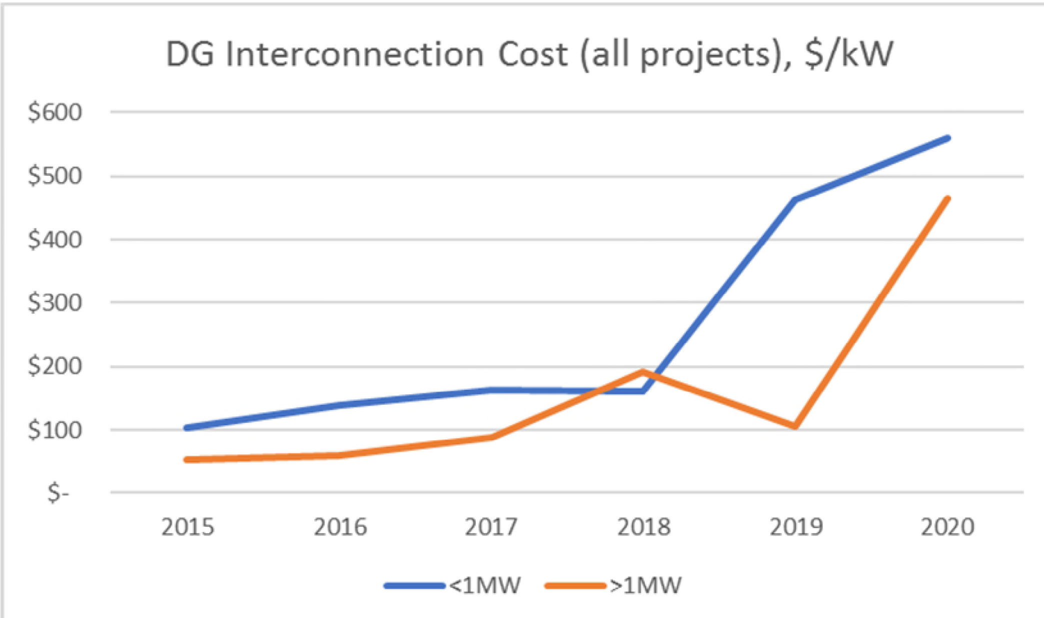

Figure 2.4: DG Interconnection Cost Trends

How and when Rhode Island moves forward with grid modernization and other distribution infrastructure changes can have wide reaching effects on DG interconnection costs, availability of clean energy, and customer control over their energy use. Independent System Operator New England (ISO-NE) states in their 2019 Regional Electricity Outlook report that opposition or impediments to infrastructure decisions will only exacerbate New England's energy-security constraints:

> The rate of policy and technological change occurring has a profound and complex impact on ***how grid resources operate and participate in the markets, how the ISO plans and runs the grid, and how consumers use and even pay for grid services***. The interaction between consumers and the electric grid will continue to evolve as consumers become more dependent on, and gain more control over, their electricity supply, but the importance of reliable, affordable electricity to society's safety, comfort, and prosperity remains unchanged. [27]

[27] ISO-New England, *2019 Regional Electricity Outlook*, 9 (2019), https://www.iso-ne.com/static-assets/documents/2019/03/2019_reo.pdf

With such a complex change comes a need to reevaluate existing processes. To start the reevaluation, a comprehensive understanding of existing distribution planning processes and current system capabilities is required.

2.2.2. Distribution System Issues

Customers are already interconnecting renewable DG, driving EVs, and participating in demand response (DR) programs at increasing rates. The electric industry expects this trend will continue and will likely escalate as customers' expectations and technologies evolve. As customers adopt more DERs, the distribution system is becoming more dynamic and complex. Each new DER interconnection has a physical impact on the grid and creates new challenges and opportunities for distribution system planning and operations. In Rhode Island, distribution operating issues are already beginning to emerge in isolated areas due to DG interconnections, and these issues will become more systematic as more DGs, EVs, and other DERs are adopted. Current system impact issues where the Company cannot maintain system reliability or safety due to DER projects without system upgrades, include:

- Overloading of conductor, line equipment, station regulators, and supply transformers
- Increase of overvoltage during minimum load conditions due to DG and in some cases low voltage during peak conditions
- Power quality and voltage fluctuation concerns in rural areas with less robust electric systems
- Ground fault overvoltage concerns
- Islanding concerns with mix of rotating and inverter-based generation with different islanding algorithms
- Protection coordination concerns, specifically desensitization of ground fault protection
- Exceeding equipment short circuit ratings

These issues are already causing the Company to develop and recommend system upgrades to accommodate new DER projects, which in some cases, result in DER project size reductions or project cancellations due to the high costs to customers and third-party developers (see *Section 2.2.1: Interconnection Issues*). Specific examples of system issues and DER project impacts, where the construction cost and timeline to integrate a DER resulted in negative economic impacts or significant project size decrease, are summarized in Attachment B, the Appendix document.

2.2.3. Distribution Planning Limitations

The long-term design of electric distribution system starts with forecasting. Focusing on maintaining a reliable system, the Company has historically used a peak load forecast. Traditionally, if a part of the distribution system could perform during the peak load period, it was assumed it could perform safely and reliably during any other period of the year. The overall approach starts with the metered peak load, which includes reductions for DER that might be operating at the time of the peak. Then, the load can be forecasted using economic factors. Next, estimates for existing energy efficiency, DR, and solar PV are added back and EV loads taken out of the metered values to create a “reconstructed” load set. In parallel, forecasts for new energy efficiency, DR, solar PV, and EV loads are created. The near-final (before weather adjustment) load forecast traditionally used for planning purposes includes the reconstructed load along with the reductions and additions from new energy efficiency, DR, solar PV, and EV forecasts.

The last step is to consider weather. Three scenarios are presented each considering different temperature and humidity impacts to the load. The weather scenarios are termed 50/50, 90/10, and 95/5, where there is a 50%, 10%, and 5% chance respectively that actual weather exceeds the scenario assumptions. Distribution planning uses the 95/5 weather adjusted forecast to ensure the system performs reliably. A Company forecast report, including all the DER and weather adjustments is issued each Fall. Details are presented in Attachment B, the Appendix.

The forecasting descriptions above include those parts of the current process that require careful consideration as the distribution system evolves. First, the assumption that “a system designed around peak loading will perform under any other time of the year” becomes less certain each year. Increasingly, the Company’s distribution planning team uses load forecasts for many different seasons and other periods of time (e.g., weekday versus weekend).[28] Second, as DER penetration increases, it becomes increasingly important to be able to accurately disaggregate system meter data into its load and generation components so that the component forecasts will have an accurate basis. Third, the type of DER components included in the forecast could increase to include distribution-level loads not currently considered, including heat electrification, energy storage, and wind generation. Each new component creates a new forecasting complexity.

After forecasting is complete, planning analysis is conducted to evaluate system performance and develop necessary recommendations for distribution system infrastructure and (when feasible) non-wires alternative (NWA) investments. Planning analysis is conducted in a variety of manners including area studies, complex customer interconnection studies, program studies, targeted reliability studies, and annual screening analysis. All analysis methods follow general problem solving steps such as:

- Scoping and Data Gathering
- Modeling
- Issue and Opportunity Identification

[28] Currently, the Company forecast includes 24-hour peak day profiles for the summer and winter seasons to show how peaks times can shift over time due to DERs. Company forecasts also include 24-hour average day profiles for the summer and winter season, shoulder months, and weekday vs. weekend to show what typical weekday and weekend loads are during average, or non-peak producing weather, and lower load shoulder seasons.

- Alternative Analysis
- Plan Recommendation

The effort and speed of each step is catered to the activity. When conducting annual system-wide screening, the data gathering needs to be simple and fast as the scope of the effort is very large and the output is a simple screen, and the alternative analysis and plan recommendation steps are not done since the intent of the screen is to inform and prioritize the more complex studies. When conducting an area study on a subset of the system with a complex modeling and analysis effort, the data gathering is more complex, and the alternative analysis and plan recommendation are critical outputs. Each step is described in further detail in Attachment B, the Appendix.

The planning process above includes certain aspects that require careful consideration as the distribution system evolves. First, planners currently rely on some manually collected data or approximated data. As the system evolves and more DER and field device data is generated, the time-consuming manual collection of data will become unwieldy, and the approximated data will become more uncertain. Second, the analysis tools need to change to accommodate substantial increases in data that represent many time periods across a year. Table 2.1 shows how the data requirements increase with the number of time periods considered. The Company is currently conducting Annual Peak and Light Load analyses for some of the Company's area studies, but the Company will need to move towards All Hour (i.e., 8760 hours/year) analyses as more DERs are introduced and granular control is required, which is a necessary functionality of the GMP.

Table 2.1: Single Feeder Example Showing Growing Data Needs

Analysis Type	Annual Peak Analysis	Annual Peak + Light Load Analysis	Seasonal Peak + Light Load Analysis	Monthly Peak + Light Load Analysis	All Hours (8760 hours/year)
Time Periods	1	2	8	24	8,760
Example # Feeder Sections	3,000	3,000	3,000	3,000	3,000
Variables Per Section	6	6	6	6	6
Data Requirements	**18,000**	**36,000**	**144,000**	**432,000**	**157,680,000**

In summary, fundamental improvements are needed to the data inputs to forecasting and planning. While the fundamental physics of electricity requiring analysis of voltage, current, and power will never change, the data to evaluate these parameters more granularly and with greater precision is increasing exponentially. This will require the proposed GMP investments, which include new methods to obtain the data and new tools to process the data.

2.2.4. Grid Design and Capability Limitations

The existing distribution system is designed and operated to maximize reliability in a safe, efficient, and affordable manner. The system is designed to accommodate customer electrical requirements with respect to how and when they demand power from the grid. Load utilization trends have been studied over many years to identify the extremes of peak usage. With these peaks identified, the system has been designed with simple autonomous controls. In the past, a system designed to handle voltage and loading concerns during the peak load periods would inherently be sufficient during off-peak periods. Specifically, the legacy distribution grid has been designed under the following paradigms:

Voltage[29]
- Voltage drop during peak periods is greater than voltage drop during off-peak periods
- Voltage levels decrease from the source end of the feeder to the remote ends of the feeder

Loading[30]
- Loading is highest during periods of peak consumption
- Load levels decrease from the source end of the feeder to the remote ends of the feeder

Fault Current[31]
- Fault current decreases from the source end of the feeder to the remote ends of the feeder

Thus, the legacy distribution grid leads to fairly straightforward sensing and monitoring requirements that can be accomplished with autonomously controlled devices. Of course, improvements and advancements in autonomous control have occurred over time and are continuing. Examples of autonomously controlled devices are provided in Table 2.2.

Table 2.2: Example of Autonomously Controlled Devices on Distribution Feeders

Category	Example Device	Prior Standard Control/Sensing	Current Standard Control/Sensing
Voltage	Switched Capacitor	Time Clock – No Sensing	Electromechanical Relay – On-Site Sensing (Amps/Volts)
Loading	Substation Ammeter	No Control – On-Site Sensing and Monitoring (i.e., Manual Reads requiring Crew Dispatch)	Analog Signal – On-site Sensing with Remote Monitoring (EMS RTU)
Fault Current	Recloser	Electromechanical Relay – On-Site Sensing	Solid State Relay – On-Site Sensing

In prior years, capacitors could be set using the historical load cycle with time clock controls. There was no on-site sensing for these installations, meaning these devices did not sense current or voltage. Common settings included switching the capacitor on at 10:00 AM as daily load was expected to increase and switching the capacitor off at 10:00 PM as the evening load was

[29] Voltage is electric potential or potential difference expressed in volts.
[30] Load is the amount of power being consumed on the electric system at any given moment.
[31] Fault current is any abnormal electric current. An open-circuit fault occurs if a circuit is interrupted by some failure.

expected to drop. With current levels of DER penetration, dependence on a daily load cycle is no longer possible and the need for on-site sensing is increasing. In response, the Company has revised its standard capacitor control to an electromechanical relay that is activated based on current (i.e., amps) and voltage (i.e., volts) at its location and switches the capacitor on or off as necessary. The Company currently replaces fixed and time-clock switched capacitor banks on an opportunistic basis or as a part of an energy conservation program such as the Company's Volt-Var Optimization / Conservation Voltage Reduction (VVO/CVR) Pilot.

For loading information, the Company has relied on source-end substation ammeters. Through modeling, the source-end loading information has been allocated throughout a distribution feeder using the "peak planning" and "one-way flow" characteristics described above. In prior years, the substation ammeters were recorded by crews during regularly scheduled inspection efforts. Under the Company's ongoing Energy Management System (EMS) Program, the ammeter data is passed through the substation's Remote Terminal Unit (RTU) at various time intervals. Today approximately 65% of the Company's distribution substations report interval information into the EMS.

System protection is another key requirement of any grid modernization plan. Fault current is a high level of amperes that flow from all generation sources into a short circuit (i.e., fault location) until it is cleared by a protective fuse, recloser or breaker. When fault current only comes from large, central generators connected to the transmission system, protective devices with on-site fault current sensing could be placed in series and set sequentially so that downstream devices operated first. Although the relays that sense the fault current have improved, offering an increased variety of settings, the fundamental sequential operation methodology has not changed.

In summary, some improvements have been made and continue to be made in sensing and control of the distribution system. However, these improvements still only support autonomous one-way devices and source-end (i.e., substation) sensing is still used to predict remote-end performance. In addition, while the Company currently replaces fixed and time-clock based switched capacitor banks on an opportunistic basis or as a part of an energy conservation program such as VVO/CVR, the current pace of deployment of such advanced capacitors and other advanced field devices is not enough to keep pace with the accumulation of DER loads forecasted in the next 10 years.

2.3. Customer Needs

Customers increasingly want cleaner, more reliable, and more affordable energy that they can manage and control. Grid modernization investments enable the Company to meet customers' evolving behavior and expectations by providing them with more energy savings opportunities, cleaner energy options, simpler and lower-cost DER interconnections, reliability improvements, and greater choice and control in addressing their energy needs compared to a future without grid modernization, including:

- Lower Energy Use: Customer's will have more opportunities to reduce their energy use due to the ability of the Company to provide greater customer energy insights and control (see Greater Customer Control described below) and operate distribution feeders at lower overall voltages

- Cleaner Energy: Customers will have a smaller carbon footprint due to reduced energy use and increased utilization of renewable resources (see Lower Energy Use described above and Improved DER Operation described in *Section 2.2: Operational Needs*)

- Affordable DER Adoption: Customers will have more affordable options to invest in their own DER technologies in areas where these technologies are most cost-effective (see Reduced DER Interconnection Costs and Improved DER Experience described in *Section 2.2: Operational Needs*)

- Improved Reliability: Customers will experience reduced outage restoration times due to the ability of the Company to more quickly locate and isolate a fault and restore power

- Greater Customer Control: Customers will have better control over their energy bills with the ability to take action based on enhanced energy use insights, integrating AMF with in-home technologies, and responding to future pricing mechanisms

If the Company takes a "do nothing" approach, customers will not have important insights into or control over their energy use, and they will miss out on substantial energy savings, reliability improvements, and important health and societal benefits like air pollutant emissions reductions. In addition, customers and developers wishing to install renewable DG will face rapidly increasing interconnection costs, and customers will face higher costs (and/or lower benefits) to adopt other DERs like EVs, energy storage, and DR, which will limit customer choice and control. With AMF, in particular, customers will benefit from enhanced outage and restoration management, and enhanced control over energy management and costs, including improved access to timely energy usage data, personalized insights and recommendations on ways to save money throughout their billing cycle, and greater access to third-party vendors offering innovative energy solutions.

In addition to these changing customer experience expectations, the grid needs to be managed more granularly, both in time and location, to continue to serve customers safely and reliably under changing grid conditions. The available technology to operate electric grids has advanced so that now is an appropriate time to implement new solutions that will cost effectively address today's constraints while being flexible enough to expand in capability to address future needs and opportunities as they evolve.

2.4. Clean Energy Needs

The Company is committed to achieving the State's clean energy policy goals and believes well-coordinated and integrated grid modernization investments are essential to meeting these goals. Recently, the Company launched a Clean Energy Promise to share our perspective on advancing clean energy in Rhode Island.[32] Included in the Company's Clean Energy Promise are four Clean Energy Pathways, including a commitment to optimize networks to deliver greater value, resiliency, and reliability, which can be achieved with grid modernization. The Company also strongly supports achieving the State's 80x50 Goal under the Resilient Rhode Island Act; Governor Raimondo's 100x30 Goal;[33] and the New England Governors' call for the modernization of the regional electricity system in order to achieve regional goals for clean, affordable, and reliable electricity.[34]

The Company believes our GMP represents the core investments necessary to meet these goals. The GMP's High DER Scenario was developed based on achieving the State's 80x50 Goal and is consistent with The Executive Climate Change Coordinating Council's (EC4) Greenhouse Gas Emissions Reduction Plan (see *Section 3.2: Future State Scenarios*). The Company is also working with external stakeholders to evaluate other, even more aggressive, DER adoption scenarios, including scenarios that achieve the Governor's 100x30 Goal.

Grid modernization investments will help Rhode Island meet its clean energy goals by enabling greater customer energy savings and DER adoption. Enabling DER adoption, in particular renewable DG, EV, and EHP adoption, is a key driver for meeting the State's clean energy needs because it will enable customers to reduce their overall emissions, including transportation-related emissions that make up 40% of the State's carbon dioxide emissions. Grid modernization investments will help reduce the costs and other barriers to interconnect new DERs in Rhode Island, which will drive more DER adoption and investment in the State.

Without grid modernization, the Company believes the electric distribution system will be a roadblock to achieving clean energy goals and the Company and State will be ill-prepared for the clean energy transition. If the Company takes a "do nothing" approach and does not invest in well-coordinated and integrated grid modernization investments, increasing interconnection cost will slow renewable DG adoption rates below the current level, EV charging infrastructure will be more-costly, and customer participation in and impact from future DER and energy efficiency programs will be limited. These consequences of a "do nothing" approach will put some of the State's ambitious clean energy goals out of reach.

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[32] https://www.nationalgridus.com/clean-energy-promise-ri

[33] https://www.nationalgridus.com/News/2020/10/National-Grid-Releases-Statement-on-New-England-Governors-8217-Call-for-Modernization-of-Regional-Electric-System-/

[34] *See* New England States Committee on Electricity (NESCOE), *New England's Regional Wholesale Electricity Markets and Organizational Structures Must Evolve for 21st Century Clean Energy Future* (2020), http://nescoe.com/wp-content/uploads/2020/10/Electricity_System_Reform_GovStatement_14Oct2020.pdf

3. Risk Management Approach

3.1. Managing Uncertainties

Developing a 10-year plan in a fast-changing environment requires acknowledgement that there are a number of uncertainties. Key uncertainties associated with the GMP include the pace, scale and location of DER adoption; technological advancement; and the development of complementary programs and services to be leveraged in the management of the distribution grid. A precise future state is difficult to predict due to the many factors that influence future demands on the distribution system, including future federal, state and local policies, regulations, and requirements; technology options and their costs; market maturity and barriers; and customer preferences. This uncertainly creates risks with respect to the scope and timing of investments within the GMP and the benefits to be achieved.

The Company has taken several steps to better understand these uncertainties and manage the associated risks, most notably creating this GMP including a 10-year roadmap to guide the development of grid modernization projects and programs. As discussed in this section, the Company has engaged with the GMP and AMF Subcommittee, participated in grid modernization research and industry forums, evaluated multiple Rhode Island future state scenarios, leveraged industry standard designs, performed a BCA following Docket No. 4600 guidance, and developed a flexible and sequenced plan of investments that can be reviewed and adjusted throughout the horizon of the plan in the appropriate regulatory forums. By these means, the GMP seeks to proactively identify needs and manage the implementation of the plan such that functionalities are delivered "just in time" so as not to be a barrier to progressing the stated objectives nor be overly costly.

3.2. Future State Scenarios

Based on the uncertainties described above, the Company recognizes that the scope and timing of the GMP investments may vary and has therefore evaluated multiple future state scenarios in developing the GMP. At one end of the spectrum, the low DER customer adoption scenario (Low DER Scenario) assumes a conservative adoption of renewable DG, EVs and EHPs based on historic (i.e., 2018-2020) DER adoption rates with an annual reduction in renewable DG adoption over time. These assumptions result in a low cumulative nameplate capacity (i.e., MW) installed for DG, and low cumulative energy (i.e., kWh) demand for beneficial electrification (BE) by 2030.[35] This scenario is based on the "Low Case" presented in the Company's 15-year distribution planning forecast.[36] The Company assessed the probability of the Low Case

[35] Beneficial electrification includes EVs, EHPs, and other electrification opportunities that reduce overall emissions and energy costs for customers.
[36] The Narragansett Electric Company, *2021 Electric Peak (MW) Forecast, 15-Year Long-Term 2021 to 2035* (Rev1, Jan. 6, 2021), https://ngrid.apps.esri.com/NGSysDataPortal/RI/index.html

occurring to be between 5-20%, depending on the DER load forecast. Specifically, Solar DG, EVs, and DR forecasts were assigned a probability of 5% each, Energy Efficiency was assigned a probability of 10%, and EHPs, which don't have a significant impact on the overall GMP cost or benefit assessment, were assigned a probability of 20%.[37]

While this level of low DER adoption assumption would have been well suited for ensuring safe, reliable, and affordable service in long-term distribution planning when peak loading was the primary concern (e.g., low voltage, overloads), it is increasingly ill-suited when significant DG is adopted on a given feeder and minimum (or negative) load is a major concern (e.g., high voltage, reverse power flow). In addition, over the 10-year horizon of the GMP, if the Company only considered the Low DER Scenario there would be a significant risk of "underbuilding" the grid, which would become a barrier for meeting evolving customer needs and increased DER interconnection expectations.

Considering scenarios with less conservative DER adoption assumptions allows the Company to monitor appropriate sign posts to proactively address distribution system needs in a timely fashion recognizing the processes and lead times required for the planning, testing, and deployment of GMP investments are much longer than the potential for rapid adoption of customer DER technologies, some of which can be purchased and in-use in a matter of hours or days (e.g., EVs, EHPs) at the individual customer-level. However, if the Company only considered high customer DER adoption scenarios (e.g., High DER Scenario, High DG Scenario, High BE Scenario) there would be a risk of "overbuilding" the grid, which would result in underutilization of distribution assets and would not maximize net benefits.
Therefore, the Company developed a set of possible customer DER adoption scenarios for consideration as part of the GMP. The GMP uses the range of DER adoption assumptions in the scenarios to evaluate the range of impacts the Company could expect on the distribution system in the future. Evaluating more than one future state scenario will also help regulators and other stakeholders make policy, investment, and other decisions that provide timely value in multiple future states.

1. Low Customer DER Adoption (Low DER) Scenario – Conservative adoption of renewable DG, EVs and EHPs based on historic (2018-2020) DER adoption rates with a 10% annual reduction in renewable DG adoption over time; DER adoption assumptions are consistent with the "Low Case" of the Company's 15-year distribution planning forecast.

2. High Customer DER Adoption (High DER) Scenario – Higher adoption of a range of DER technologies including renewable DG, EV and EHP consistent with achieving

[37] Probability assignments were based on group consensus of internal subject matter experts and sum to 100% for one of four scenarios. The probabilities for each DER forecast are assumed to be independent of each other.

Rhode Island's 2050 goal of 80% GHG emissions reductions compared to a 1990 baseline (i.e., 80x50 Goal); DER adoption assumptions are consistent with the "High Case" of the Company's 15-year distribution planning forecast[38] and are similar to Rhode Island's Executive Climate Change Coordinating Council (EC4) Greenhouse Gas Emissions Reduction Plan.[39,40]

3. High Customer DG Adoption (High DG) Scenario – High adoption of renewable DG based on achieving the State's 80x50 Goal, but assuming a more conservative adoption of EV and EHP.

4. High Customer BE Adoption (High BE) Scenario – High adoption of EV and EHP based on achieving the State's 80x50 Goal, but assuming a more conservative adoption of renewable DG; EV and EHP adoption assumptions are consistent with National Grid's Northeast Pathways Study.

Each scenario is defined by its 2030 customer DER adoption assumptions summarized in Table 3.1. The DER assumptions are based on the Company's review of industry forecasts and input from internal subject matter experts. Details are also presented in the Attachment B, the Appendix.[41]

Table 3.1: 2030 Customer DER Adoption Assumptions for Future State Scenarios

2030 Future State Scenario Assumptions	1) Low DER	2) High DER	3) High DG	4) High BE
EVs On-Road, total number	9,000	243,000	80,000	400,000
EHPs In-Use, total households	<1,000	82,000	30,000	110,000
Solar DG, MW installed	950	1,400	2,100	800
Wind DG, MW installed	85	270	270	270

Hourly (i.e., 8760 hours/year) demand forecasts were created for each DER type and added to the Rhode Island "base load" (including economic growth and energy efficiency reductions) to assess the distribution system impacts of each scenario. These hourly forecasts were used in a "top-down" assessment of aggregated net load duration curves for Rhode Island to identify

[38] The Company assessed the probability of the High Case occurring to be between 5-35%, depending on the DER load forecast. Specifically, Solar DG forecast, which has a significant impact on the overall GMP cost and benefit assessment, was assigned a probability of 35%; EV forecast was assigned a probability of 10%; and Energy Efficiency, DR, and EHP forecasts were assigned a probability of 5% each. Probability assignments were based on group consensus of internal subject matter experts and sum to 100% for one of four scenarios. The probabilities for each DER forecast are assumed to be independent of each other.

[39] EC4, *Rhode Island Greenhouse Gas Emissions Reduction Plan* (December 2016).

[40] Acadia Center, *2030 Energy Vision: Transitioning to a Low-Emissions Energy System in the Northeast* 201.7.

[41] Note that the High DER customer adoption scenario used in the GMP is not exactly the same as the "High Case" published in the Company's 2020 Electric Peak Forecast. The GMP High DER scenario was developed to be consistent with meeting the 80x50 Goal, so DER adoption is a little higher than the Company's 2020 Forecast "High Case."

potential impacts and opportunities at a macro level, and a "bottom-up" assessment using detailed feeder-level load flow models to identify the emergence of local constraints through the year 2030. Evaluating the scenarios at this level of granularity enables the Company to understand both the long-term needs but also provides insight as to the emergence and progression of the needs so that a more sequenced and flexible GMP can be implemented.

To simplify the computations necessary to develop a quantitative BCA, the Company selected the Low DER and High DER scenarios for the detailed BCA. The Company believes these two scenarios "bookend" the range of issues the Company will likely encounter on the distribution system in the future. The High DG and High BE scenarios were modeled as part of the Future State Assessment, but they were not quantified in the BCA.

3.3. Leveraging Industry Standards and Flexible Designs

As noted in *Section 1.7 Alignment with National Grid Jurisdictions*, the Company is actively engaged in shaping grid modernization activities within the industry, including ongoing work with IEEE, NEC, EPRI, CEATI, and DOE. The Company has taken what it has learned from these industry engagements to shape this GMP. In addition, the Company proactively explores new technology opportunities through industry events such as DistribuTECH, IEEE Power and Energy Society Transmission and Distribution (T&D) conferences and frequent engagements with vendors. As promising technologies are identified, the Company assesses the new equipment for inclusion within its Distribution Standards so that it may be safely, reliably and cost effectively deployed and integrated within grid operations. Standardizing on devices included in the GMP such as capacitors, regulators, reclosers and their advanced controllers and telecommunications radios allows for cost effective design, procurement and personnel training. For similar reasons, the Company also seeks to leverage common platforms and information management to the extent possible. For example, the Company's control center applications for EMS, Outage Management System (OMS), and the proposed ADMS will share a common platform, and the Company's GIS models will be the basis for load flow modeling for both planning and operations.

3.4. Benefit-Cost Analysis

To evaluate the cost effectiveness of the grid modernization portfolio of investments, considering the system impacts that may arise over the range of the future state scenarios, the Company has developed a quantitative BCA for the GMP that is aligned with Docket No. 4600 Guidance. The GMP BCA is intended to compare the relative costs and benefits of GMP investments anticipated through 2030. The assessment compares distribution system plans that utilize technologies that provide integrated modern grid capabilities (referred to as the grid modernization cases) to a plan that is limited to more traditional infrastructure upgrades and autonomously controlled equipment (referred to as the reference case). The scope of the BCA is limited to Company investments in grid modernization, and therefore the GMP BCA is not intended to evaluate if the customer DER adoption scenarios or policy targets themselves are cost effective.

In addition to providing information in terms of how the quantifiable benefits and costs compare for the range of future scenarios, the GMP BCA also provides the Company and external stakeholders with a better understanding of the key factors that impact the quantifiable benefits and costs and allows all parties to focus future efforts on better understanding and influencing those factors in a positive way.

3.5. Roadmap and Implementation Plan Approach

The GMP proposes a series of grid modernization investments over the course of the 10-year horizon rather than proposing to implement the full suite of investments that could be needed via a single project or program. Maintaining a longer-term roadmap to guide near-term implementations will foster stakeholder engagement, aid in identifying synergies between projects, ensure maximization of net benefits, and create efficiencies through standardization. Cost recovery requests for each grid modernization investment will be made through future filings in existing forums including annual ISR Plans and future rate cases, and possibly System Reliability Procurement (SRP) and annual Energy Efficiency proceedings as the need arises. In addition, the Company believes it would be most appropriate if the GMP were refreshed on at least a three- to five-year cycle in concert with future rate case proceedings. In doing so, a current GMP would act as a reference document in support of the grid modernization investments included with applicable filings submitted to the PUC for review and approval.

The 10-year roadmap in *Section 5.7: 2030 Roadmap* and the 5-year implementation plans in the *Implementation Plan* document, present a sequenced progression of investments, deploying field devices in a targeted and incremental fashion, and developing IT platforms that are flexible and scalable. For example, the suite of Control Center and Back Office tools utilized by distribution system operators will operate off a common expandable ADMS platform. The ADMS platform will be developed in phases that begin with core functionalities such as as-operated load flow modeling and state estimation. Expanding the capabilities of the platform to gain additional benefit with functionalities such as VVO/CVR, FLISR, and advanced protection is expected to occur in future phases that will be justified on their individual merits and presented in future rate cases.

Likewise, the installation of feeder monitoring sensors, and advanced capacitors, regulators, reclosers, and breakers will be identified and recommended via traditional planning processes and incorporated into the Company's capital investments plans and annual ISR filings. The Company has existing standard designs and equipment that will be utilized for near-term installations. If more enhanced functionality becomes necessary, such as the use of stat-var compensators, smart inverters, and adaptive relays, the Company standards will be updated to make the new tools available to the Company's engineers and designers.

The GMP is a flexible and sequenced plan of investments that can be reviewed and adjusted throughout the horizon of the plan in the appropriate regulatory forums. Importantly, the GMP proposes a set of foundational infrastructure investments through multi-year rate cases with commonalities across all future DER scenarios that ensure flexibility regardless of future customer DER adoption. Investments in advanced field devices will be requested through annual ISRs as needed based on on-going assessment of the load forecast and its potential impact on the distribution system. By these means, the GMP seeks to proactively identify needs and manage the implementation of the plan such that functionalities are delivered "just in time" so as not to be a barrier to progressing the stated objectives nor be overly costly.

In addition, the effectiveness of the GMP and the pace and scale of its implementation will be impacted by the evolution of future policies, regulations, and requirements. These impacts are further discussed in *Section 4.3, Complementary and Supporting Elements*. While the development of these complementary policies, regulations, and requirements is beyond the scope of the GMP, assumptions concerning their future authorization are inherent in the GMP roadmap and associated BCA.

3.5.1. Annual ISR Reviews

Recognizing that the ISR Plans contain a one-year review of the Company's pending capital investments and spending plan, many of the GMP investments may be submitted for formal review in future ISR Plans. For example, DG may develop in the western portion of the state such that the Company determines the area is experiencing the risks described within this GMP. At that time, the Company would progress a project or projects to deploy advanced field devices on the feeders in that area as part of the ISR Plan and in alignment with this GMP. While no two feeders are exactly alike in terms of distance, customers, and number of devices, this GMP evaluated a range of sample feeders to provide a reasonable indication of expected results, which has been used to develop the implementation plans, roadmap, and estimate the GMP benefits and costs.

The GMP will also serve to align future ISR proposals with the overarching GMP functions and goals to avoid obsolescence and redundancy. As the Company advances projects, it would do so in a comprehensive manner considering the other programs and projects within the ISR plans. For example, grid modernization efforts in any area need to be closely aligned with the EMS program and VVO/CVR programs that may be a part of the ISR Plan. Specifically, substation and telecommunications efforts would be coordinated to gain efficiencies. In this manner, the Company can demonstrate that its proposals are efficient considering the state of the system at the time of proposal, and that they are as aligned as reasonably possible with a variety of future states. In addition, the tools the GMP will provide for distribution planning in general will provide a much more granular look at where and how NWA projects could provide system solutions.

The Company also recognizes that technology, policies, and procedures can change faster than contemplated within this 10-year roadmap. This could impact what projects are ultimately presented in future ISR plans. For example, high penetrations of smart inverters, the associated telecommunications infrastructure, and the tariffs, policies, and procedures to establish an operations-focused DER Management System (DERMS) might require advancing DERMS functionalities faster than anticipated. This, in turn, may necessitate a change in the number of advanced capacitors proposed within future ISR Plans compared to the volume presented in this GMP. The Company will continue to analyze the evolving energy system and adjust the grid modernization investment proposals as necessary.

3.5.2. Periodic Rate Case Authorizations

Investments included in the ISR are generally limited to Company's capital investments, but many of the GMP investments include IT systems and other back office systems that can be leveraged by other National Grid affiliates (e.g., GIS, ADMS, Cyber Security). These shared assets will generally be owned by the National Grid USA Service Company and the costs for the Company's use of those systems will be accounted for through an allocated annual operating and maintenance (O&M) rental expense. The cost recovery of these, and other, expenses will generally be presented in periodic multi-year rate case proceedings and more details on these proposals will be presented at that time.

3.5.3. Innovation and Technology Readiness Projects

The Company proposes to continue to develop a better understanding of uncertainties and manage risks by undertaking Innovation and Technology Readiness (ITR) pilot projects. Through the ITR pilot projects, the Company will continue to engage with the GMP and AMF Subcommittee and participate in grid modernization technology evaluation in order to refine the assumed GMP costs, benefits, and implementation plans, so they can be reviewed and adjusted throughout the horizon of the plan.

ITR investments will fund the pilot projects necessary to support cost-effective deployment of the future grid modernization solutions presented in the GMP, particularly solutions that are less-well defined, like DERMS, or solutions with additional functionality that can be further explored to increase net benefits, like the System Data Portal, AMF, ADMS, VVO/CVR, or FLISR. The Company anticipates selecting 2-3 ITR topic areas and prioritizing one project per topic consistent with GMP goals and objectives. The Company anticipates completing up to three ITR projects in each of two phases coinciding with two future rate case periods, or up to six projects total over six years. Completion of each phase is assumed to be over the term of each rate case (i.e., 3 years each). Overall, ITR projects will help identify and evaluate GMP innovation and technology readiness opportunities and will enable the Company to implement grid modernization as quickly and cost-effectively as possible and provide the most value to customers. Details are presented in the Implementation Plan document.

4. Current Grid Modernization Activities

4.1. 2017 Rate Case Funding for Grid Modernization

Under the terms of the ASA, the Company is already progressing efforts on a number of initiatives including developing requirements for, and in some cases implementing, the following solutions: AMF Business Case, System Data Portal, GIS Data Enhancements, ADMS Core Functionality, Underlying IT Infrastructure (i.e., Enterprise Service Bus, Data Lake, and Advanced Data Analytics), Appropriate Cyber Services, and Operational Telecommunications.

During Rate Year 1 (September 2018 – August 2019) of the MRP, the Company created and staffed an internal organization to support the consistent and coordinated activities of all the shared investments for grid modernization. This included establishing a Project Management Office and establishing the program frameworks and controls for managing the broad portfolio. The Company progressed an effort to define and develop a Grid Modernization Capability Model as part of defining the business and technical architecture for the program. The model is intended to serve as a foundation to support traceability of capabilities back to strategic objectives and guide the development of future use cases, requirements, technical architecture, and technical decisions.

During Rate Year 2 (September 2019 – August 2020), the Company used the capability model to inform the development of a broader business and technical architecture. This effort looked at the holistic grid modernization portfolio and developed a conceptual technical model and technical design principles to guide the various investment areas. The Company also looked at the broader real estate of solutions to determine whether the grid modernization requirements and capabilities could be supported through extending existing products and solutions or pursuing more fit for purpose products and solutions.

Below is a summary of the specific work completed to date under the current MRP for each specific technology investment area.

- **AMF Business Case**: The Company has refined and updated the AMF Business Case based on extensive feedback from the GMP and AMF Subcommittee, updated Company forecasts and research, updated cost inputs from the Company's AMF Request for Solution (RFS), and the expanded application of the Docket No. 4600 Benefit-Cost framework, among others. Subcommittee feedback was gathered through a series of stakeholder collaboration meetings and stakeholder review of materials during that time. Feedback from the subcommittee was used to enhance all components of the AMF proposal (e.g., Business Case, BCA, and all supporting attachments).

- **System Data Portal**: The Company has delivered and continues to maintain the System Data Portal. The costs incurred to date and planned for the rest of Rate Year 3 are based on maintenance and support, enhancement requests, and the underlying infrastructure expense. The Company added two full-time equivalents (FTEs) to its workforce through Rate Year 2, including one incremental FTE in the Asset Data & Analytics (ADA) group in December 2018 and one incremental FTE in Distribution Planning & Asset Management (DPAM) in June 2019. While there are no specific data portal enhancements identified at this time, new enhancements are expected to originate from collaborative consultation between the Company and external stakeholders through SRP planning or other forums.

- **GIS Data Enhancements**: The Company has initiated and is progressing the GIS Phase 1 project with an expected completion date of June 2021. This Phase 1 work will deliver upgrades and changes to our GIS platform to accommodate new asset types, equipment and data attributes (data model changes), and additional tools and enhanced features to manage data quality and improve processes in GIS. GIS data improvements and data hardening are underway, which includes general data cleanup as well as changes to baseline GIS to allow for new asset types, new equipment, expanded attributes, and characteristics. Going forward, GIS data cleanup and data model changes will continue and changes to GIS to support these requirements for ADMS will be progressed.

- **ADMS**: The Company has completed an analysis and scoping effort for the development of the ADMS project. Business capabilities and system requirements have been captured. Phase 1 ADMS system design activities are complete, major vendor contracts are in place, and hardware and software have been procured. Infrastructure build out and system testing are in progress. A thorough analysis of operational procedures affected by the rollout of an ADMS as well as a review of change impacts and training requirements is complete. This will ensure the solution fits as designed into the Company's operations, is properly adopted, and delivers expected benefits. Going forward, the project will be implemented utilizing a phased approach putting different modules and functionality into service over the next four years. This will maximize value and benefits realization as early as possible as well as help to align ADMS with critical dependencies such as GIS Data Enhancements and RTU Separation work. The Company has also procured an enterprise software license from the PI software vendor and has conducted preliminary architecture discussions on the deployment architecture for the new Distribution PI Historian platform.

- **RTU Separation**: As part of the overall ADMS work stream, the Company also performed detailed scoping and planning of the initial RTU Separation work, completed RTU Separation for five substations, and initiated engineering and design for two of the three planned major RTU separation projects.

- **Underlying IT infrastructure**: The Company has completed an architecture assessment of the current integration tools in use, and their fitment for the Grid Modernization Program. In addition, the Enterprise Service Bus (ESB) platform has been selected and requirements, design and development efforts in progress are expected to be completed and placed into service for all jurisdictions by December 2021. The Data Lake effort was initiated in Rate Year 2 and is expected to complete the initial platform in August 2021 and then be placed into service for all jurisdictions. The Advanced Analytics effort experienced alterations to the initial assumptions based on the planning and scoping for ESB and Data Lake initiatives but planning and scoping have been completed including requirements for Data Catalog and Data Quality, Business Capabilities, High Level Data Use Cases, and Preliminary Data Source identification.

- **Cyber Security**: Applicable cyber security threats have been mapped to the grid modernization business capabilities to assess how they may be impacted by those threats if they were to be realized. In addition, the implementation plan for the integration of cyber security services and the grid modernization workstreams have been drafted to ensure services are available when needed. During the next rate year, appropriate Cyber Services detailed requirements and design will be started for all jurisdictions and will be deployed and/or enhanced to support the grid modernization workstreams.

- **Telecommunications**: The Company initiated planning and scoping to engineer, design, manage, and deliver a network of devices and connectivity in collaboration with the preferred vendor for AMF. The Company also initiated the planning and scoping for the Data Lake and Advanced Analytics efforts, which will inform incremental telecommunication bandwidth investments. New telecommunication needs for AMF and other grid modernization investments will continue through the next rate year.

A summary of each major grid modernization project approved in the 2017 Rate Case, Company spending to date (and projected spending through RY3), and cost recovery status is presented in Table 4.1.

Table 4.1: Grid Modernization Project Spending for 2017 Rate Case Investments[42]

Grid Modernization Project Spend, $ million (Real$)	RY1 2018-2019	RY2 2019-2020	RY3 (projected) 2020-2021	Cost Recovery Status
AMF Business Case	$2.01	$0.24	$0.09	Approved in 2018 MRP
System Data Portal	$0.23	$0.47	$0.47	Approved in 2018 MRP
GIS Data Enhancements	$0.07	$0.87	$1.58	Approved in 2018 MRP
ADMS	$0.06	$1.86	$4.03	Approved in 2018 MRP
RTU Separation	$0.06	$0.05	$0.21	Approved in 2018 MRP
Underlying IT infrastructure	$0.00	$0.25	$0.99	Approved in 2018 MRP
Cyber Security	$0.00	$0.27	$0.82	Approved in 2018 MRP
Telecommunications	$0.01	$0.33	$1.12	Approved in 2018 MRP
Total	**$2.44**	**$4.34**	**$9.31**	

4.2. Other Grid Modernization Activities

In addition to the 2017 Rate Case funding for initial Service Company investments in grid modernization, the Company has also deployed advanced field devices and VVO/CVR on select feeders over the last 3-5 years. The Company has deployed VVO/CVR capability through approved investments in feeder monitoring sensors, advanced capacitors and regulators, and a stand-alone VVO/CVR control platform through Company's VVO/CVR Pilot program funded through the ISR. To date, the Company has implemented VVO/CVR on 19 feeders from 6 substations in Rhode Island. Implementation of VVO/CVR has included the deployment of 44 feeder monitoring sensors, 122 advanced capacitors, and 52 advanced regulators. Deployment on an additional 14 feeders at three substations is anticipated through the Company's FY21 ISR Plan[43] based on the initial positive results. The Company has also deployed 453 advanced reclosers on over 200 feeders in Rhode Island as part of customer requests for DER interconnections (22 midline reclosers and 66 PCC reclosers)[44] and all other Company programs requiring new reclosers including for safety/reliability, damage/failure, and asset replacement (365 midline reclosers).

The 2018 ASA only covered a three-year period ending in Rate Year (RY) 2021 and the most recent ISR only covers a one-year period ending in FY21. The roadmap and implementation plans presented in this GMP provide information related to progress on that initial work as well as future efforts associated with grid modernization envisioned from 2021 (FY22) through 2030 (FY31).

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[42] ADMS Core Functionality investments include DSCADA/ADMS and Distribution PI Historian project spending and RY3 projections. Underlying IT Infrastructure investments include ESB, Data Lake, and Advanced Analytics project spending and FY3 projections.

[43] *See The Narragansett Elec. Co. d/b/a National Grid, 2021 Electric Infrastructure, Safety, and Reliability Plan*, Docket No. 4995 (Submitted December 20, 2019) [hereinafter FY 2021 ISR Plan].

[44] Point of common coupling or "PCC" means the point where the generating facility's local electric power system connects to the utility's electric system.

4.3. Complementary and Supporting Elements

4.3.1. Polices, Regulations, and Requirements

The effectiveness of the GMP and the pace and scale of its implementation will be impacted by the evolution of future policies, regulations, and requirements. Therefore, the Company is implementing the GMP investments over time, with continued engagement from technology developers, regulators, and other stakeholders. While the development of these future policies, regulations, and requirements is beyond the scope of the GMP, assumptions concerning their future authorization are inherent in the GMP roadmap and associated BCA.

The following potential future policies, regulations, and requirements are expected to impact the evolution of the GMP:

- **Time-Varying Rates**: The GMP envisions that time-varying rates (TVR) will be a primary driver of load shifting through customer load management programs.[45] The Updated AMF Business Case includes the Company's intent to file a TVR proposal in the next suitable filing before the AMF solution becomes operational. As customers become accustomed to TVR, more advanced rates that better align price signals to electricity costs can be implemented to help shift customer demand away from higher cost periods of time.[46] It should be noted that the AMF meters being proposed as part of the GMP have interval metering and the ability to perform over the air software and firmware updates to allow re-programming as needed. Therefore, any expansion or changes to TVR can occur without requiring the meter to be replaced.

- **DG Tariffs, Flexible Interconnection Standards, and Distribution System Operating Requirements**: The GMP envisions that some combination of an expanded DG interconnection tariff with some level of flexibility on how DG can or should operate, and/or operating requirements for grid injections from DG and energy storage will be necessary to optimize DER output for the benefit of the grid, customers, DER developers, and society. Current practices whereby DERs are not dispatchable will be problematic at high DER penetration levels, and future policies and regulations on the interconnection tariff and operating requirements will need to consider how best to leverage these technologies. It should be noted that the same reprogrammable and interval AMF meters being proposed for rate-paying customers will also be used for most DER customers. Therefore, any expansion or changes to the DG tariff could occur without requiring the DER meter to be replaced. In addition, the use of raw interval data can be manipulated by

[45] Customer load management programs are defined here as customer-facing programs that can be used by distribution planners and operators to better manage the distribution system to achieve compliance or optimization goals.
[46] "More advanced rates" may reference mechanisms such as Real Time Pricing, residential demand charges, and others discussed in Attachment C of the Updated AMF Business Case.

the AMF's meter data management system (MDMS) to allow for numerous billing scenarios, including time varying rates.

- **Smart Inverters:** The variable nature of many DERs, especially distributed solar and wind generation, presents voltage and frequency challenges on the electric grid. One promising technical solution to help address these challenges is so-called "smart inverters." Unlike traditional inverters that are designed to run at unity power factor, smart inverters can absorb and generate reactive power to help reduce fluctuations in the output voltage of the facility as well as help manage voltage on the distribution system. Smart inverters can also reduce their output power generation at times to avoid escalating system conditions (i.e., over-frequency conditions) and can respond to power curtailment commands, which could be delivered via a DERMS when excessive DER power is being pushed back to the transmission system. Therefore, the Company has included a smart inverter demonstration in the 2021 Energy Efficiency Plan. If approved, this demonstration will improve power factor and provide voltage support. If this demonstration is successful, the Company will look to add on more power quality improvement strategies with smart inverters in future Energy Efficiency Plans. Additional details about smart inverters are presented in Attachment B, the Appendix.

4.3.2. Load Management Programs

With granular data obtained by advanced field devices and AMF, the electric distribution system could more effectively progress residential and small commercial DER market-facing or customer-facing programs, which customers and other stakeholders are increasingly interested in. Likewise, the effectiveness of the GMP solutions will be impacted by the pace, scale, and effectiveness of various DER market-facing and customer-facing programs, particularly load management programs.

Customer-facing load management programs, like energy efficiency and DR programs, can be used to lower the cost of wholesale electricity, reduce the bulk system's peak demand, and address generation, transmission, and distribution constraints. DER market-facing load management programs, like the NWA program, are still evaluating the role that DERs can play in helping to address distribution-level constraints and reducing distribution-level peak demand. In the future, under high DER penetration scenarios, load management programs including DR, EE, NWA, EV, and Energy Storage programs can be used in combination with TVR and/or new DG tariffs to not only reduce bulk and distribution-level peak loads, but also shift customer loads to times when excessive DG output power exceeds the grid's ability to accommodate the load. Details are provided in *Section 7.3: Quantitative Benefit-Cost Analysis*.

The following current and potential future load management programs are expected to impact the evolution of the GMP:

- **Energy Efficiency:** Although today's energy efficiency portfolio generates system benefits at capacity, transmission, and distribution levels, the portfolio is generally focused on bulk system level (capacity and transmission) and not the constraints of the local distribution system. The Company envisions future energy efficiency customer offerings that will optimize demand side resources to achieve an efficient and resilient grid on both the wholesale and distribution levels. The Company has been working, and will continue to work, to progress the integration of Distribution Planning with Energy Efficiency to further identify opportunities to address constraints on the distribution system, which can lower the cost of electricity delivery. New enhancements to the Energy Efficiency program will be proposed through annual Energy Efficiency Plan filings.

- **Demand Response (DR)**: Building within the energy efficiency programs, both residential and commercial DR programs play a critical role in helping Rhode Island contribute its share to peak load reduction and improving power quality, which produces system benefits at the capacity, transmission, and distribution levels. However, like the rest of the energy efficiency portfolio, DR today is generally focused on the bulk system level and not the constraints of the local distribution system. The Company is looking into extending the DR programs to provide support to distribution-level NWAs using existing DR and DERMS infrastructure. Today, the Company's DR programs utilize a DERMS that is exclusively used for behind-the-meter (BTM) distributed energy resources (DERs). The management of front-of-the-meter (FTM) resources such as power plants, solar farms, and Company owned resources are not within the purview of the energy efficiency portfolio. Today, the Company's DERMS manages DERs such as Wi-Fi thermostats, electric vehicles, and batteries, generators, CHP, solar inverters, HVAC systems, lighting systems, industrial processes, and other BTM DERs. Current BTM DERMS functionalities include handling customer/vendor registration, event dispatch, and performance calculations. New enhancements to the DR program will be proposed through annual Energy Efficiency Plan or SRP filings. In the future, an extended DERMS deployment, including FTM functionalities, envisioned by this GMP, will enable DR performance for more customer DERs. In addition, the deployment of AMF for residential and small commercial customers will establish a basis for the implementation of TVR, in turn providing improved price signals to residential and small commercial customers, which could provide wholesale-level peak-load reduction.

- **Non-Wires Alternatives (NWA)**: NWA is an inclusive term for any targeted electrical grid investment that is intended to defer or remove the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment." NWA projects are required to meet the specified electrical grid need and be cost-effective compared to the traditional "wires" investment. An NWA project can include any action, strategy, program, or technology that meets this definition and these requirements. In the near-term, grid modernization will help identify and fairly compensate NWA projects, which may result in an increase of NWA projects. The NWA process will also benefit from more granular system operational data, customer load data, and other information from AMF and advanced field devices, as planners will be able to better evaluate and forecast system loads and better predict the timing (e.g., time of day, month of year) of potential thermal or voltage issues. This refined understanding of the system constraints will enable a better understanding of the NWA need, permit NWA design optimization, and facilitate more cost-effective NWA projects. In the longer term, grid modernization, combined with new revised rules on DG operation and TVR, may reduce or possibly eliminate the need for what are considered NWAs today; as the integration of TVR, energy efficiency, DG, and DR become part of the modern grid.

- **Energy Storage**: The Energy Storage Demonstration approved in Docket No. 4770 will support customers in adopting energy storage technologies in the near-term. This program can positively contribute to changes in customer preferences for energy management and help uncover the best value proposition for energy storage. The current residential, commercial, and industrial customer DR programs also include the management of BTM energy storage for peak load reduction. In the future, with more granular system operational data enabled by advanced field devices and AMF, and the overall management and control enabled by ADMS and DERMS, customer's energy storage assets can be used to help manage load on the distribution system for the benefit of all customers. New enhancements to energy storage programs will be proposed through future rate cases, annual Energy Efficiency Plans, and/or the SRP plans.

- **Transportation and Heat Electrification**: The Electric Transportation Initiative approved in Docket No. 4770 and future Beneficial Heat Electrification programs will support customers in adopting BE technologies in the near-term.[47] These programs can positively contribute to changes in customer preferences for a shift towards clean energy and electrification that customers seek. If not properly managed, new electrification loads can have a negative impact on the distribution system by increasing peak load.[48] However, if properly managed through a well-coordinated and integrated GMP that employs load management techniques along with TVR, these new electrification loads can be shifted away from periods of peak demand on the distribution system to periods of low demand and/or high DG output, which can reduce distribution infrastructure investment, and, in the future, can help minimize negative load periods due to excess renewable DG output. New enhancements to BE programs will be proposed through future rate cases, annual Energy Efficiency Plans, and/or the SRP plans.

[47] Currently, the Company's energy efficiency programs do not provide incentives for customer conversions from delivered fuels-based heating to electrification of heating with heat pumps.

[48] Although the Company believes future EHP loads are not likely to impact the Rhode Island distribution system peak load as a whole in the next 10 years, local impacts may be felt in areas pre-disposed to winter peak loading issues and with high early adoption of EHPs, particularly adoption of air source heat pumps. Air source heat pumps have higher electric demand than ground source heat pumps, particularly at lower ambient temperatures.

4.3.3. Transmission System Costs

The Rhode Island GMP presents a holistic plan of activities and investments expected to be necessary for Rhode Island's changing distribution electric system. The distribution system is the portion of the electric system that is composed of medium-voltage (35 kV to 4 kV) subtransmission lines,[49] substations, distribution feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage (115 kV and above) transmission system. The Transmission-Distribution interface (T-D interface) is the physical point at which the transmission system and distribution system interconnect. This point is often the demarcation between federal and state regulatory jurisdiction. It is also a reference point for electric system planning, scheduling of power and, in ISO and Regional Transmission Organization (RTO) markets, the reference point for determining Locational Marginal Prices (LMP) of wholesale energy.

Although future distribution system activities and investments will impact the transmission system, and vice versa, it is beyond the scope of this GMP to evaluate the suite of transmission-level activities and investments that would be necessary in the future. For example, when the Renewable Energy Growth program began in the late 2000s, it also expanded the eligibility for remote net metering applications, which has resulted in multiple renewable "distributed generation" interconnection applications (e.g., multiple 10 MW Solar DG projects) for the same location. The resulting "distributed generation" capability at the location can be greater than 20 MW, which requires a transmission study. These types of large interconnections (>20 MW) often require the construction of dedicated substations and related T&D equipment, similar to off-shore wind or other large "bulk generation" projects. Therefore, the activities and investments needed to accommodate these large renewable generation projects are specifically excluded from the Rhode Island GMP due to the fact that these installations are largely accommodated at the transmission and bulk system levels.

Below is a summary of the key differences between these very large "distributed generation" installations and traditional DG installations.

Traditional DG Projects (<5 MW)

- Traditional DG projects can help reduce peak load on the distribution system, which could potentially defer some peak load-related distribution system infrastructure investment in some locations (at least in the near-term)

- Grid modernization investments will help reduce interconnection costs

[49] In Rhode Island, the subtransmission system includes distribution circuits typically between 15kV class and 35kV class, which can supply other distribution substations, large DG, or customers with high electric loads.

- System Data Portal can typically help guide customers and third-party DER developers towards locations with lower interconnection costs (i.e., locations with higher hosting capacity)
- Grid modernization will likely help reduce transmission system upgrade costs if any are needed

Very Large-scale "DG" Projects (>5 MW)

- Very large-scale "DG" projects will not help reduce peak load on the distribution system because these large projects typically require a dedicated substation and new wires/conductors
- Grid modernization will not likely help reduce interconnection costs
- System Data Portal will not be very useful for such large systems – high interconnection costs are unavoidable under the current paradigm
- Grid modernization can help reduce some transmission-system upgrade costs, but there will likely still be large transmission system upgrade costs regardless of grid modernization

However, the distribution-level investments proposed as part of the GMP can still have a beneficial impact on the transmission system. For example, without grid modernization investments, the current high saturation of existing and proposed DG projects has already resulted in the need for additional capacity from the Company's transmission provider, New England Power (NEP), and potentially new T-D interfaces will need to be constructed (e.g., substations and transmission lines). These transmission system capacity additions have a significant cost, which can be avoided or reduced in the future using the proposed grid modernization technologies that can better manage loads on the distribution system. In addition, GMP investments will provide increasing levels of information and visibility on the distribution system, which can be passed on to ISO-NE, so they can better manage transmission-level loads. Transmission-level benefits relating to streamlining DER interconnections and reduced transmission study costs are addressed qualitatively in *Section 8.6: Qualitative Assessment.*

5. Planning Analysis and Recommendation

This GMP considers grid modernization needs through the year 2030 (FY31). Customer expectations, available technology, and policy and regulatory objectives are expected to evolve over this horizon, therefore the GMP must consider a range of possible future needs and be flexible enough to adapt in a timely and efficient manner. For this reason, the GMP considered a number of future scenarios and evaluated the range of potential impacts on the distribution

system. Considering these evaluations, the GMP 2030 Roadmap seeks to plan and operate the grid in a more granular fashion so that all available resources (utility, customer and third party) can be utilized to most cost-effectively meet the identified needs and stated objectives.
The GMP seeks to develop capabilities that result in an ability for the Company to proactively plan for the needs of the grid and operate in a fashion that is responsive to customer expectations. Grid modernization is not accomplished through a single project or program. Rather, grid modernization is an evolutionary journey on which the Company has already begun. Grid modernization will be deployed in a phased manner and integrated over time. Flexibility has been built in to allow the ability to maximize net benefits and realize new functionalities where and when they are needed.

5.1. Overview

To select a set of grid modernization solutions that will meet Rhode Island's needs through 2030, the Company followed the stepwise approach outlined in Figure 5.1, which is consistent with the Planning Analysis steps presented in *Section 2.2.3: Distribution Planning Limitations*. First, GMP objectives were identified based on customers' expectations and state goals, particularly Docket No. 4600 "goals of the new electric system." Then, modeling scenarios were developed using a range of customer DER adoption assumptions with consideration of the GMP objectives. Next, a future state assessment was conducted to study these scenarios, which led to a set of necessary grid modernization functionalities and potential benefit impacts. Then, a proposed solution set and ten-year roadmap necessary to realize those capabilities and functionalities were identified. Finally, a detailed BCA was developed based on the solutions identified in the 10-year roadmap and internal estimates for the costs and benefits of the portfolio of solutions. The BCA is discussed in more detail in *Section 8: BCA Evaluation Under Docket 4600*.

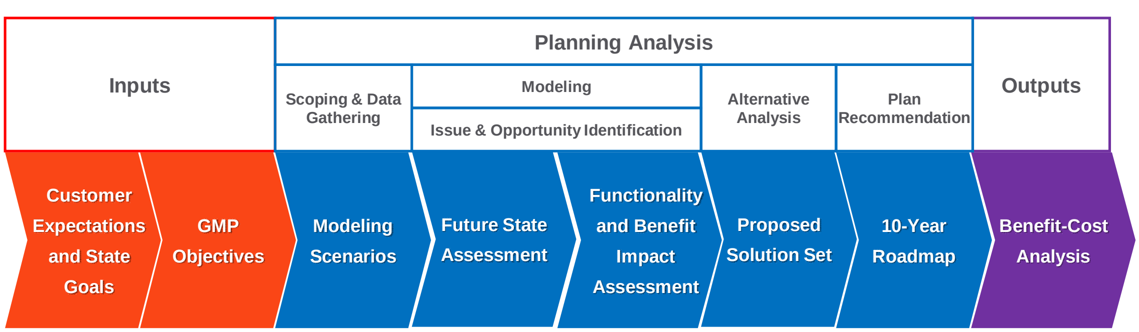

Figure 5.1: Illustration of GMP Solution Assessment Approach

5.2. Goals and Objectives

The first step was to identify the GMP goals and objectives based on customers' expectations and needs, State goals, including a review of the relevant Dockets, particularly Docket No. 4600 "goals of the new electric system", which are presented in *Section 1.6: Alignment with Docket*

No. 4600 Goals. The Docket No. 4600 goals embrace the important question of "What can and should the new electric system be able to accomplish?" Evaluation of these expectations and goals resulted in three key GMP goals. Table 5.1 shows the alignment between the Docket No. 4600 goals and GMP goals.

Table 5.1: Alignment Between Docket No. 4600 Goals and Rhode Island GMP Goals

<table>
<tr><th>Docket No. 4600 Goals</th><th>GMP Goals</th></tr>
<tr><td>Empower customers to manage their costs</td><td rowspan="6">1) Give customers more energy choices and information</td></tr>
<tr><td>Customer education and engagement programs to provide all customers with the information and tools to optimize their electricity consumption</td></tr>
<tr><td>Provide opportunities to reduce energy burden</td></tr>
<tr><td>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</td></tr>
<tr><td>Appropriately charge customers for the cost they impose on the grid</td></tr>
<tr><td>Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society</td></tr>
<tr><td>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)</td><td rowspan="3">2) Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term</td></tr>
<tr><td>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</td></tr>
<tr><td>Appropriately compensate the distribution utility for the services it provides</td></tr>
<tr><td>Address the challenge of climate change and other forms of pollution</td><td rowspan="2">3) Build a flexible grid to integrate more clean energy generation</td></tr>
<tr><td>Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentive</td></tr>
</table>

In addition, by working with internal and external stakeholders to develop a shared vision of the future, specific GMP objectives were identified for each GMP goal. Developing a shared vision involved assessing where the distribution grid is now (see *Section 2: Today's Grid*) and where it can realistically expect to be in the future. Ten key objectives developed as part of this visioning are summarized below. Each key objective is categorized under the most relevant GMP goal:

1) Give customers more energy choices and information
   a) Inform customers about their energy use and energy choices
   b) Provide enhanced energy management capabilities
   c) Enable customers to invest in their own DER technologies and promote investment in areas that are most cost effective for these resources
   d) Ensure that all customer and grid facing data is kept safe, secure, private, stored and maintained through robust data governance and management

2) Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term
   a) Develop a more efficient grid through greater monitoring and control of grid side and customer side devices
   b) Ensure safety and reliability are maintained or improved with increasing levels of DER adoption
   c) Ensure new pricing and allocation mechanisms to attribute costs and benefits more equitably

3) Build a flexible grid to integrate more clean energy generation
   a) Enable higher penetration of clean DERs into the grid
   b) Effectively manage emerging two-way power flows in a reliable, safe, clean and affordable manner
   c) Enable better assessment of the locational and temporal value DER may provide to the electric system

5.3. Modeling Scenarios

To assess the scope and scale of potential distribution system needs over the ten-year horizon of the GMP, the Company developed multiple customer DER adoption scenarios with varying levels of renewable DG interconnection and BE adoption within the transportation and heating sectors. While a high customer DER adoption future is envisioned, there is uncertainty with respect to where and when the DER will be interconnected. Therefore, two primary customer DER adoption scenarios were developed to “bookend” a range of possible future outcomes: 1) a low DER adoption (Low DER) scenario based on historic (2018-2020) DER adoption rates with an annual reduction in renewable DG adoption over time, and 2) a higher DER adoption (High DER) scenario consistent with achieving Rhode Island’s 2050 goal of 80% greenhouse gas emissions reductions compared to a 1990 baseline (80x50 goal). Based on the High DER Scenario assessment, the Company determined that the current levels of renewable DG adoption will need to continue and beneficial electrification adoption will need to increase significantly in order to achieve the 80x50 goal. Scenario details are provided in *Section 3.2: Future State Scenarios*.

To properly model future DER impacts, research was conducted on a variety of DER categories to enable modeling for planning analysis. For example, inverter efficiency and hourly solar incidence was gathered for solar PV.[50] Similarly, EV research included battery types, state mileage averages, charger characteristics, and charger use coincidence.[51] Then, emission reductions were tied to DER type, and DER types and amounts tied to power load cycles for planning analysis. New techniques were applied to existing planning tools to handle 8,760 hours per year across multiple years and across a variety of load and generation types. The Company

[50] Primarily using National Renewable Energy Laboratory’s PVWatts Calculator, https://pvwatts.nrel.gov/
[51] Started with U.S. Department of Energy’s EVI-Pro tool, https://afdc.energy.gov/evi-pro-lite

used a manual, labor-intensive process leveraging existing tools to complete this GMP analysis, noting that new advanced planning tools would be necessary in the very near future.

5.4. Future State Assessment

Considering these scenarios, the Company evaluated the potential future DER impact on state-wide load curves for each hour of the year (*i.e.*, 4,760 hours/year) through 2030. Additionally, detailed distribution load flow models were created on a small representative sample of distribution feeders to identify the scale and magnitude of local operational constraints that would arise under the various loading scenarios with and without grid modernization investments out to 2030. Summaries of both the feeder-level and state-level modeling are provided below, and details are presented in Attachment B, the Appendix.

5.4.1. Feeder-Level Analysis

With the ability to model the future, the next step was to determine the system-level issues of that future. The Company divided this task into two parts: compliance and optimization. "Compliance" is assumed to be the traditional utility purpose of managing loading and voltage within guidelines and managing protection systems to maximize reliability and worker and public safety. "Optimization" refers to a refinement to the traditional utility goals that enables additional customer benefits. For example, with the necessary advanced controls in place for proper voltage compliance, voltage optimization (i.e., VVO/CVR functionality) can be added to provide customer energy savings. Specifically, the Company's DER Enabling Investments recently proposed in the FY21 ISR Plan is an example of a compliance investment,[52] while the Company's VVO/CVR pilot program funded through the FY18-21 ISR plans is an example of an optimization investment. Similarly, with the necessary protection systems upgraded (i.e., advanced reclosers and breakers) to handle DER flows and cycles for compliance, FLISR becomes a very cost-effective additional optimization investment. As a result, the capabilities and functionalities of the future system remain the same – management of voltage, loading, and reliability but with an eye towards optimization opportunities.

Key findings from the feeder-level analysis include:

- Distribution operating issues (e.g., high voltage, protection system coordination), which are already beginning to emerge in isolated areas in Rhode Island, will become more systemic at higher DER penetrations.

- Although there will be some coincidence between commercial "workplace" EV charging and the timing of solar DG injections, there is generally a mismatch between solar DG injections and typical late day and evening residential EV charging.

[52] *See* FY 2021 ISR Plan, *supra* note 43.

- High levels of renewable DG adoption will impact the grid more significantly during light loading (e.g., off-peak) periods than peak periods. During light loading periods, significant renewable DG curtailment may be required (see State-Level Analysis below).

- High penetrations of DER will significantly impact voltage regulation: BE will lead to more low voltage violations during on-peak periods, and renewable DG injections will lead to more high voltage violations during light loading periods. Therefore, advanced voltage control schemes will be required to manage voltage during both on-peak and light loading periods.

- Significant swings in loading and the prevalence of two-way power flows caused by renewable DG will require more adaptive relay protection schemes to properly coordinate circuit breakers to ensure worker safety and the reliable operation of the grid.

- The Company will need enhanced data handling and processing power for both distribution system planning and real-time grid operations. For this GMP study, a labor-intensive manual process was used that will not be sustainable at scale. Similarly, processing certain cases required many hours to complete.

Without a well-coordinated and integrated GMP, the Company would need to design and build traditional distribution infrastructure to accommodate future DER growth and address the issues described above.

5.4.2. State-Level Analysis

The High DER Scenario modeled as part of the state-level analysis resulted in a net load curve with several negative load periods due to the prevalence of renewable DG, particularly solar DG. This means that renewable DG would be in excess of load - or in other words, at times there would be more renewable DG available than Rhode Island customers needed at that time. Figure 5.2 shows the minimum, maximum, and average daily state-level load cycle across seasons projected for 2030 under the High DER Scenario. The figure shows the load bounds during a particular hour in a season within which the system is expected to perform. Across each day within a season, the system load could be at any point between the minimum and maximum lines. As can be seen in Figure 5.2, negative load occurs during some daytime hours when too much electricity is fed into the grid from renewable DG in relation to customer demand. Unless this negative load can be eliminated, high voltages and thermal congestion will result. Note that this load projection is based on the High DER Scenario forecast for Rhode Island and excludes off-shore wind generation or other transmission-connected wholesale generation.

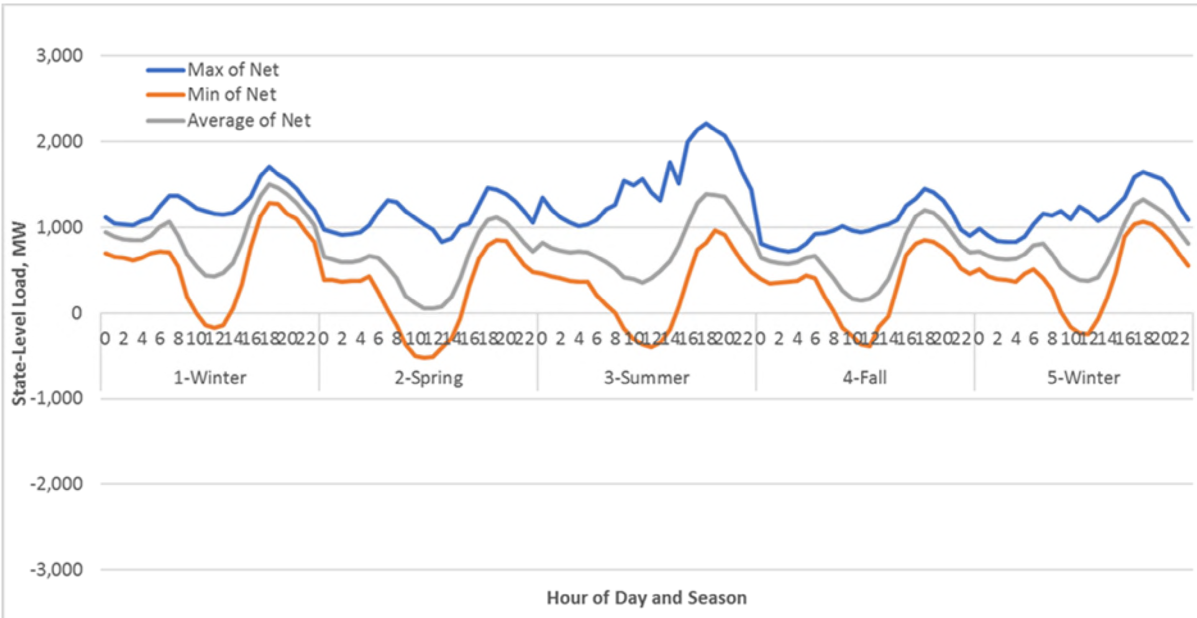

Figure 5.2: State-level load cycle across seasons projected for 2030 under the High DER Scenario

Under a low regional renewable generation future and with no constraints on the transmission system, a valid assumption might be that excess renewable DG from Rhode Island could be exported to surrounding states. However, the Future State Assessment under the High DER Scenario assumes that the surrounding states in the region, all of whom participate in the Regional Greenhouse Gas Initiative (RGGI), will have similar renewable generation adoption, such that exporting excess generation to other states will be challenging. Even if other states in the region could easily absorb the excess generation from Rhode Island, the necessary state and regional transmission system capacity could require significant upgrades under the High DER Scenario. Transmission-level upgrades to address thermal overloads or voltage issues can cost developers and ratepayers tens of millions of dollars and take between 5-7 years to complete.[53]

Therefore, the GMP assumes DG curtailment, rather than upgrading the transmission system and exporting excess generation, is the most viable option for most excess renewable DG generation through 2030 under the High DER Scenario. However, without grid modernization investments, grid issues due to excess DG generation can't be monitored or managed (*i.e.*, curtailed) in a granular manner using sensors, ADMS, smart inverter controls, DERMS, or other means. So, the Future State Assessment "Reference Case" (without grid modernization) assumes the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the design limitations of the system, which in this case is the estimated seasonal minimum load for the State. This "seasonal curtailment" results in an

[53] National Grid, *Central & Western MA ASO Cluster Study Update* (March 19, 2020), https://ngus.force.com/servlet/servlet.FileDownload?file=0150W00000EoGc8

average renewable DG curtailment of 20% of its annual energy output under the High DER Scenario by 2030.

This level of renewable DG curtailment would not only make most DG projects uneconomic, it also goes against Rhode Island's environmental and economic goals. This level of curtailment significantly reduces the output from the renewable plants in which the State has invested, and it would require the State to overbuild renewable resources and potentially increase renewable DG incentives in order to meet the State's Clean Energy Goals (e.g., 80x50, 100x30 Goal). The level of solar DG curtailment envisioned in the High DER Scenario Reference Case would not be acceptable for most DG projects, but without grid modernization investments, alternatives are limited. Possible alternatives to renewable DG curtailment include the following:

- **Load Shifting**: Options to enable load shifting include advanced DR programs, particularly targeting loads from future EV charging and integrated customer energy storage. However, shifting customer load to periods when renewable generation is most abundant (*i.e*., 7 am – 3 pm for solar DG) reliably and at the large scale necessary for the High DER Scenario is not envisioned to be possible without the customer information, granular monitoring, and control that are central to AMF and other grid modernization investments.

  Dedicated Energy Storage: Electrochemical (i.e., battery), kinetic, thermal, or other forms of energy storage are promising approaches to absorb excess renewable DG power and discharge the excess power during periods of high demand, but their ability to shift load to address excess renewable DG requires granular monitoring and control that are central to the grid modernization investments. In addition, costs for most energy storage technologies are still very high. To absorb the amount of daily excess renewable energy necessary in the High DER Scenario would require a significant amount of energy storage at relatively high cost.[54]

- **Transmission System Expansion**: Expanding the current transmission system so the State's excess renewable DG can be exported to other states and regions that could cost-effectively utilize it is outside of the GMP's scope of work. Because export feasibility is greatly dependent on size, location, and timing of the DG, it is difficult to estimate what types of transmission infrastructure investments will be necessary. If significant upgrades are necessary, transmission investment will be costly, take many years to

[54] For example, utility-scale lithium-ion battery systems large enough to accommodate the largest potential negative load period in the Reference Case would need to be sized for at least 550 MW and 2,800 MWh (assuming 8-9 hours of charging during solar peak periods and 8-9 hours of discharging during other load periods each day) under the High DER Scenario. The costs for such a network of batteries could exceed $800 million in CAPEX assuming $300/kWh for the battery system. By comparison, the GMP investments in the High DER Scenario total $537 million in CAPEX for all GMP solutions (nominal 20-year cost) excluding AMF and provide significant additional benefits beyond avoiding seasonal DG curtailment.

complete, and result in suboptimal benefits compared to grid modernization investments. While a full-scale transmission system buildout to accommodate all potential excess renewable DG generation in the State is not likely to be a cost-effective solution through 2030, targeted transmission expansion is expected to provide important benefits and complement distribution-level grid modernization.

- **Renewable Power-to-gas (P2G)**: Renewable P2G uses water and renewable electricity to generate hydrogen gas. The resulting hydrogen gas can be used directly or combined with natural gas or biogas or combined with carbon dioxide to produce methane or liquefied petroleum gas (LPG). While this approach holds promise in the longer-term, it is not expected to be cost effective on a State-wide scale due to high capital and energy costs and low utilization factors before 2030.

The most likely outcome based on these limitations, and without investments in grid modernization, is that renewable DG adoption would be significantly inhibited in the State. Renewable DG projects would be uneconomic due to excessive curtailment requirements,[55] or due to substantial energy storage or transmission upgrade costs. Therefore, the State would likely need to introduce much higher DG incentives to offset the additional DG project costs, or DG adoption in the State would be restricted such that achieving the State's clean energy goals could be at risk.

5.5. Functionality and Benefit Impacts Assessment

Next, the Company was able to determine the grid modernization capabilities and functionalities necessary to address the issues identified by the Future State Assessment consistent with the GMP goals and objectives. To identify the full set of potential grid modernization functionalities that could address the issues, the Company considered the functionalities identified by the DOE Modern Grid Initiative (DSPx) guidance for applicability in Rhode Island during the horizon of the GMP.[56] The DOE DSPx multi-volume guides offer a comprehensive view of the potential technologies and functionalities needed to effectively manage the evolving distribution grid. The Company has actively participated in workshops and provided feedback in support of the DOE's development of these guides.

Subject matter experts from across the Company evaluated each DSPx functionality for its relevance to the objectives of the Rhode Island GMP and its ability to address the issues identified by the Future State Assessment. Based on this evaluation, a set of necessary grid

[55] Large DG curtailment requirements, typically anything greater than 10%, can result in unfavorable DG project economics.
[56] DOE's Modern Grid Initiative works with public and private partners to develop the concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future. Multi-volume guidance documents are available on the Pacific Northwest Laboratory's website, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

modernization functionalities for Rhode Island was selected. For example, the Future State Assessment identified the need for greater voltage and load control, so a number of grid modernization functionalities were selected to address these needs. Each functionality was then categorized based on its overall grid modernization capability, including: Data Acquisition capabilities that are required to better integrate and control monitoring and control devices in the field; Monitoring & Control and System Modeling & Analytics capabilities that can be used by distribution system planners and operators for improved planning and operations; Customer Enablement capabilities that can be used by both rate-paying customers and DER customers to enable customer choice and control; and Optimization capabilities that can be used with the other grid modernization capabilities to optimize the distribution system for the benefit of customers.

The selected functionalities and capabilities are presented in Table 5.2. Definitions for each key functionality are presented in Attachment B,the Appendix.

Table 5.2: Rhode Island Grid Modernization Capabilities and Functionalities

Grid Modernization Capability	Grid Modernization Functionality
Data Acquisition	Operational Information Management Cyber Security Operational Telecommunications
Monitoring & Control	Observability (Monitoring & Sensing) Distribution grid control (i.e., voltage control and fault management for compliance, flow control and state estimation)
System Modeling & Analytics	Distribution System Representation (Network Models) Grid Optimization
Customer Enablement	Advanced Metering (Customer Information, Advanced Pricing, Remote Metering) Distribution System Information Sharing
Optimization	Voltage Control for Optimization Reliability Management DER Operational Control

After the necessary functionalities were selected, subject matter experts were further engaged to develop a set of potential benefit impacts for each functionality. The Company evaluated the DOE DSPx documents and BCAs conducted for other Company programs (e.g., EE, DR, NWA) to ensure a comprehensive list of potential benefit impacts were considered. The Company also surveyed several other utility filings for AMF and grid modernization plans. The results of the survey are included in Attachment B, the Appendix. The expected benefit impacts are presented in Table 5.3 for each selected grid modernization functionality.

Table 5.3: Expected Benefit Impacts for Each Functionality

Grid Modernization Functionality	Expected Benefit Impacts
Customer Information	• Reduces system capacity requirements and customer energy use by encouraging customers to reduce their energy use based on enhanced insights (such as high usage alerts) from more granular, timely energy usage data; and potentially integration with in-home technologies • Enhances customer choice and control by providing customers with improved energy usage information and access to third party service providers, empowering customers to better understand and prioritize among solutions to best manage energy usage and costs; and allows for innovative demand-side management programs
Advanced Pricing	• Reduces system capacity requirements and customer energy costs by enabling customers to respond to price signals that can reduce demand for energy during peak demand periods, and/or increase demand for energy during negative load (i.e., excess renewable DG) periods
Remote Metering	• Improves operational efficiency by enabling the Company to eliminate O&M costs associated with meter reading, investigations, and visits to connect and disconnect service • Reduce average outage duration for customers due to improved outage notification capabilities
Distribution System Information Sharing	• Enables improved DER location selection, streamlined DER interconnection processes, reductions in time to interconnect, and better customer and third party information sharing and services by showing customers and DER providers where the most cost-effective interconnection locations are on the distribution system
Observability (Monitoring & Sensing)	• Enables system planners and operators to design and operate the distribution system in a more flexible and efficient manner. This functionality is a foundational element and supports all other key functionalities.
Power Quality Management	• Reduces system capacity requirements and customer energy use by enabling the system operator to manage voltage impacts of renewable DERs and operate distribution feeders at lower overall voltages (within ANSI limits), which reduces electricity consumption and peak demand from customer appliances
Distribution Grid Control	• Enables the system operator to rearrange the distribution feeders and maximize the load-to-generation balance to avoid thermal issues
Distribution System Representation (Network Models)	• Provides a topological model of the physical distribution system and customer and DER connectivity. This functionality is a foundational element and supports all other key functionalities.

Table 5.3: Expected Benefit Impacts for Each Functionality

Grid Modernization Functionality	Expected Benefit Impacts
Grid Optimization	• Enables the system operator to autonomously or remotely control power flows on the distribution system and optimize power output from DERs rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints
Operational Analysis & Forecasting	• Provides the ability to perform dynamic assessment of the state of the distribution system to inform real-time contingency planning, system operations including switching plans, and operational controls and DER dispatch. This functionality is a foundational element and supports all other key functionalities.
Operational Information Management	• Provides operational data recording, processing, and storage to support operational businesses functions and processes. This functionality is a foundational element and supports all other key functionalities.
Cyber Security	• Provides protection of cyber assets (e.g., computer hardware and software, information) from theft, damage, disruption or misdirection of the services they provide. This functionality is a foundational element and supports all other key functionalities.
Operational Telecommunications	• Provides highly reliable connectivity under both normal and degraded system operating conditions. This functionality is a foundational element and supports all other key functionalities.
Reliability Management	• Reduces customer outage time by enabling the system operator to quickly identify and reconfigure the system rather than waiting for phone calls from customers to identify an outage, and field crews to locate and restore outages • Reduces customer outage time by enabling the system operator to quickly develop efficient and optimal switch orders
DER Operational Control	• Reduces DG curtailment by enabling the system operator to manage DERs and optimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints • Streamlines DER interconnections by enabling larger and lower cost DER interconnections

As can be seen, each key functionality resulted in one or more expected benefit impacts. Benefits are described in more detail in the Implementation Plan document, and a detailed benefit impact assessment is presented in *Section 8: BCA Evaluation Under Docket No. 4600*. Details describing how AMF supports each of the GMP functionalities are presented in *Section 7: AMF Roadmap and Grid Modernization Integration.*

5.6. Proposed Solution Set

Next, an Alternative Analysis was conducted by subject matter experts from across the Company to evaluate the most appropriate solutions that enable the key functionalities listed in Table 5.2. The Company drew upon its experience demonstrating and deploying grid modernization solutions in Rhode Island, Massachusetts, and New York, and reviewed and considered solutions identified by external experts (e.g., DOE DSPx, EPRI, CEATI) to ensure the most cost-effective solutions were selected for applicability in Rhode Island during the horizon of the GMP.
Table 5.4 summarizes the selected solutions to progress each of the modern grid functionalities identified in Table 5.2 and 5.3. Solutions highlighted in orange are those that include investments for which funding was approved in the 2017 Rate Case or ISR dockets. Solutions highlighted in blue are future investments envisioned in this GMP. Future investments would be presented for cost recovery in future rate cases, ISR plans, or AMF docket considering the “sign posts” discussed in *Section 6: Accountability*.

Table 5.4: Solutions Selected for Each Functionality

Grid Modernization Functionality	Selected Solutions
Advanced Metering (Customer Information, Advanced Pricing, Remote Metering)	AMF (CEMP, GBC, Integration w/ In-Home Technologies, Interval Energy Usage Data, Remote Interval Meter Reading, Remote Connect & Disconnect)
Distribution System Information Sharing	System Data Portal
Observability (Monitoring & Sensing)	AMF (Load & Voltage Data) Feeder Monitoring Sensors (Compliance) Advanced Capacitors & Regulators (Compliance) Advanced Reclosers & Breakers (Compliance)
Power Quality Management for Compliance	ADMS Core Functionality (Voltage Control)
	Advanced Capacitors & Regulators (Compliance)
Power Quality Management for Optimization	Advanced Capacitors & Regulators (Optimization) Feeder Monitoring Sensors (Optimization) Existing VVO/CVR Platform
	AMF (Load & Voltage Data); ADMS-based VVO/CVR Platform[57]
Distribution Grid Control	ADMS Core Functionality (DSCADA)
	Advanced Reclosers & Breakers (Compliance) ADMS-based Protection & Arc Flash Application[58] AMF (Load & Voltage Data)
Distribution System Representation (Network Models)	GIS Data Enhancements
Grid Optimization	ADMS Core Functionality (System Monitoring, State Estimating, Switching)
	AMF (Load & Voltage Data)
Operational Analysis & Forecasting	ADMS Core Functionality (Visualization, Simulation & Analysis)
Operational Information Management	Underlying IT Infrastructure (Data Management, Enterprise Integration Platform, Corporate PI Historian)
Cyber Security	Appropriate Cyber Services
Operational Telecommunications	Network Management (INOC, TOMS, DMX)
	OpTel Strategy (Private Network)
Reliability Management	Advanced Reclosers & Breakers (Optimization) AMF (Automated Outage & Restoration Notification, Granular Fault Location); ADMS-based FLISR[59]
DER Operational Control	DERMS AMF (Remote Interval Meter Reading, Load & Voltage Data, Operational Telecommunications (Tier 3))

[57] ADMS-based VVO/CVR will also contribute to Power Quality Management for Compliance and Distribution Grid Control as more DERs are adopted, particularly in the High DER Adoption Scenario.
[58] ADMS-based Protection & Arc Flash will also contribute to Distribution Grid Control as more DERs are adopted, particularly in the High DER Adoption Scenario.
[59] ADMS-based FLISR will also contribute to Distribution Grid Control as more DERs are adopted, particularly in the High DER Adoption Scenario.

The elements of the GMP are very inter-related and new capabilities will be achieved through their effective integration. A number of functionalities can be enabled by more than one solution, and a number of the solutions contribute to enabling more than one grid modernization functionality. In practice, most functionalities require more solutions than are listed. For example, almost all functionalities require foundational investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Network Management.

Table 5.5 below summarizes what each of the solutions is and what it does in the context of the GMP. Detailed descriptions are presented in the Implementation Plan document.

Table 5.5: Grid Modernization Solution Definition Summary

Grid Modernization Solution	What it is? What it does?
AMF	Smart metering technology that will capture and transmit customer energy usage data on an hourly or sub-hourly basis. This technology enables customer energy management (e.g., CEMP), customer energy information sharing (e.g., GBC), advanced pricing options (e.g., TVR), remote metering and service (e.g., on/off) capabilities, and granular distribution system information.
System Data Portal	Internet-based portal that provides distribution data to Rhode Island customers and third-party DER developers, so they can identify areas where DERs will likely be most beneficial and avoid areas where integrating DERs may be problematic or costly. The proposed GMP investment will encompass continued maintenance and development of the existing portal with relevant distribution system and planning information to facilitate DER integration in the best locations and as cost-effectively as possible.
Feeder Monitoring Sensors	Accelerated deployment of interval power measurement devices that can monitor distribution system performance remotely and help manage capacity and voltage along individual distribution feeders.
Advanced Capacitors & Regulators	Accelerated deployment of capacitors and regulators with advanced controls and sensing to manage voltage within ANSI voltage standards, targeting those areas and feeders with existing DER penetration and the greatest voltage compliance risk.
Advanced Reclosers & Breakers	Accelerated deployment of reclosers and breakers with advanced controls and sensing to ensure distribution equipment is operated within its rated capacity and that faults on the system are cleared efficiently, targeting those areas and feeders with existing DER penetration and the greatest overload and/or protection coordination risk.
GIS Data Enhancements	Enhanced software and processes that will be used as the authoritative source for distribution asset information and network configuration (i.e., connected model) to support ADMS and other requirements of the integrated modern grid.
ADMS Core Functionality	Software and hardware that will support distribution control room operations by providing greater visibility, situation awareness, and optimization of the distribution system.[60]
ADMS-based Protection & Arc Flash Application	Software that will support implementation of adaptive protection systems that can respond to changing fault conditions to properly coordinate circuit protective devices to ensure worker safety and the reliable operation of the grid.
Data Management	IT platform to house internal and external data (e.g., asset, meter, land development, weather, real estate) that will ensure the proper data are made available for analytics and that these data are properly controlled.
Enterprise Integration Platform[61]	IT platform that can be leveraged to integrate various objects within the network and enable the exchange of information between systems, services and devices.
Corporate PI Historian	IT service that records hundreds of thousands of pieces of raw operational data generated by intelligent electronic devices being monitored and controlled in a modernized grid SCADA system.

Grid Modernization Solution	What it is? What it does?
Appropriate Cyber Services	IT services to protect customers and electric grid operations from a vast array of threats from new vectors as more devices, including third-party devices, are connected and integrated with utility operations.
Network Management	IT communications technologies that collect meter and T&D system data to support AMF and the integrated modern grid.
OpTel Strategy	Operational telecommunications (OpTel) investments to develop a secure, private OpTel network to accommodate the Company's electric distribution system with improved performance and cost-effectiveness.
VVO/CVR Platform	Accelerated deployment of software with control schemes to coordinate multiple voltage regulating devices (i.e., Advanced Capacitors & Regulators) on a feeder to achieve optimal CVR performance and reduce customer demand and energy use.
ADMS-based FLISR Application	Software with overlaying control scheme to coordinate multiple load management devices (i.e., Advanced Reclosers & Breakers) on a feeder to achieve fast, reliable, and safe FLISR, which can reduce customer outage restoration time.
DERMS	Suite of software tools to integrate customer controlled DER resources with grid operations, including dispatching DER in a manner that maintains the security of the distribution system while ensuring an optimal economic solution.
ITR Pilot Projects	Small-scale pilot projects designed to mimic important aspects of key topics/investments of the GMP that require further investigation prior to full-scale roll out, reducing the risks to rate payers.

In short, the portfolio of projects and initiatives presented in the GMP focuses on the need to leverage granular customer data, manage the distribution grid more granularly, and build a flexible grid to 1) give customers more energy choices and information; 2) ensure clean, reliable, and affordable energy to benefit Rhode Island customers over the long term; and 3) integrate more clean energy generation into distribution planning and operations for the benefit of customers.

5.7. 2030 Roadmap

The Company's grid modernization roadmap initially focuses on foundational elements of a future grid that can be enhanced as needed over time to deliver new functionalities where and when they are needed. Examples of this approach include the phasing of ADMS functions and the deployment of Advanced Field Devices based on planning studies and proposed as part of annual ISR plans. Figure 5.2 summarizes the solutions, expected timing, and expected filing for cost recovery of GMP investments over the next ten years. Solutions highlighted in yellow are those that include investments that are aligned with the recent rate case and ISR dockets, and solutions highlighted in blue are future investments envisioned in this GMP.

[60] Includes Remote Terminal Unit (RTU) separation, which is an expanded effort to modify or replace hardware to segregate distribution data from transmission data to avoid potential security concerns and enable integration of RTU's into the DSCADA and ADMS.
[61] Referred to as Enterprise Service Bus (ESB) in the 2017 Rate Case.

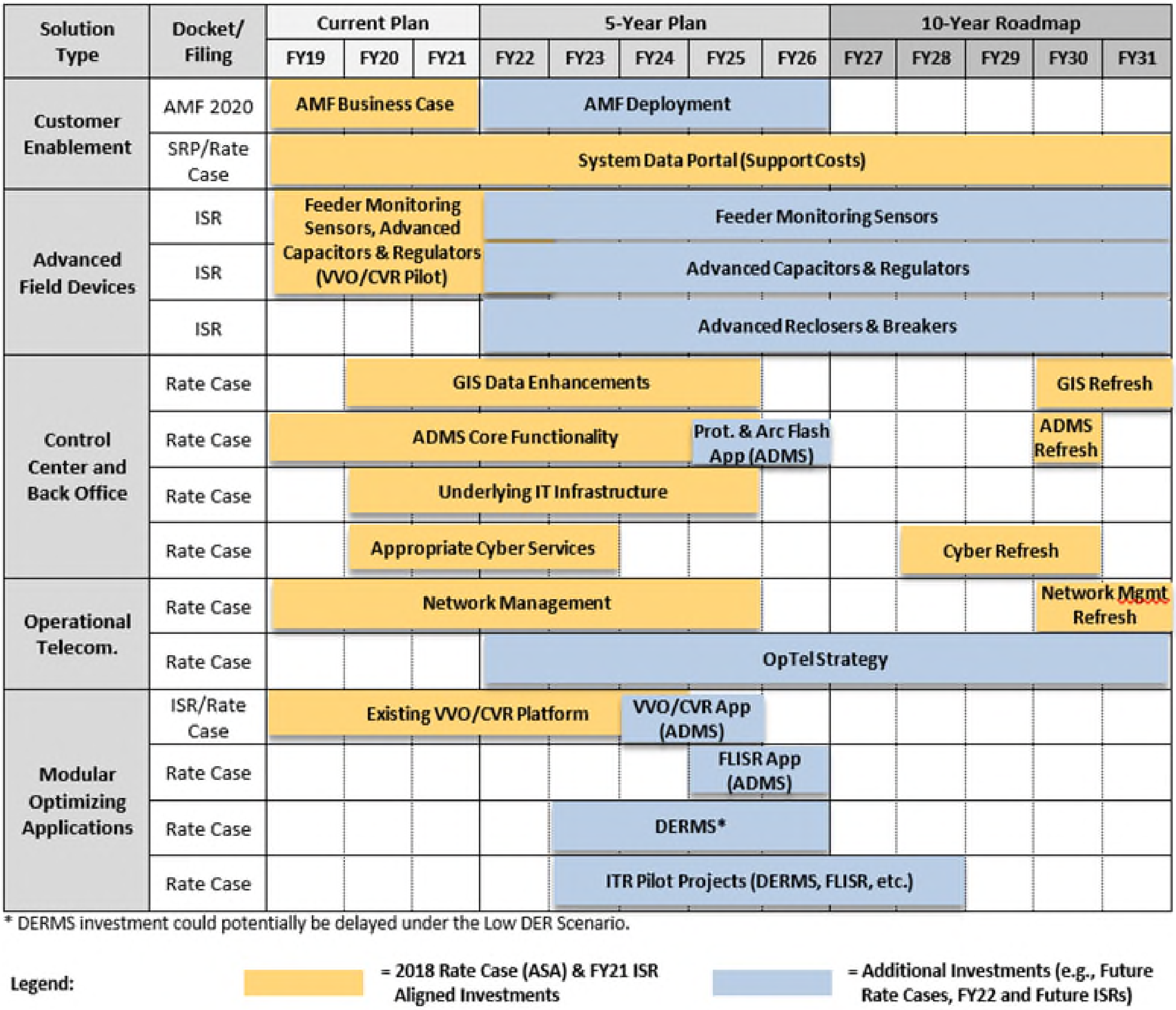

Figure 5.2: Rhode Island Grid Modernization Solutions Roadmap

As can be seen, the GMP's initial investments are focused on the foundational elements, including Customer Enablement, Control Center & Back Office, Telecommunications, and Advanced Field Devices. Deployment of Advanced Field Devices will be driven by future DER forecasts and planning study reviews to ensure the grid can be operated in compliance with existing standards and targets. Opportunities to optimize performance for the benefit of customers will be targeted to the areas of greatest value by leveraging the foundational investments with additional Modular Optimizing Applications, like VVO/CVR, FLISR, and DERMS. Innovation and Technology Readiness (ITR) investments will fund the pilot projects necessary to support cost-effective deployment of optimizing applications that can maximize customer benefits. This approach will allow the Company to efficiently leverage the functionalities and new technologies, programs, and services to meet evolving customer expectations and grid needs.

The 2030 Roadmap presents a sequenced progression of grid modernization investments, deploying field devices in a targeted and incremental fashion, and developing information platforms that are flexible and scalable. Implementation plans will deliver initial foundational functionalities, which include enhancements and upgrades to existing Rate Case investments in GIS, ADMS, Underlying IT Infrastructure, Appropriate Cyber Services, and Network Management (Telecommunications); as well as development and deployment of new investments in AMF, OpTel Strategy, ADMS-based application solutions (i.e., Protection and Arc Flash App, VVO/CVR App, FLISR App), and DERMS. Likewise, the installation of Advanced Field Devices (i.e., feeder monitoring sensors~~,~~ and advanced capacitors, regulators, reclosers, and breakers) and an Existing VVO/CVR Platform will be identified and recommended via traditional planning processes and incorporated into the Company's capital investment plans and annual ISR filings.

5.8. Alignment with Ongoing Activities

The GMP investments align with and support ongoing planning activities. First, the GMP investments will improve the planning process by providing granular feeder data from Advanced Field Devices or even more granular AMF data for planning area studies. With the additional data and the functionality provided by GMP assets, planners can move from recommendations focused on peak and light load periods to recommendations focused on all times of the year. This will improve both the timing and scope of the planned investments presented in the annual ISR filings.

In addition to improvements to the area study and planning processes, certain programs and devices currently approved through the ISR and SRP filings will be affected. For example, the capital investment plan considered within the annual ISR filing includes control center and field device investments. ISR programs like the EMS Program can be adjusted to include grid modernization so EMS functionality is provided at substations in coordination with feeders being modernized. Similarly, pending replacement of field devices will be evaluated to grid modernization standards to prevent early obsolescence. Proposed investments in NWA projects or planned improvements to the System Data Portal, which are included in SRP filings, may also be impacted by GMP investments. For example, the GMP considers DERMS as an important investment that effectively enables wide-scale NWA projects to assist with system operations. DERMS-related NWA investments would be described within SRP.

While grid modernization can enable a more efficient management of the grid, complementary policies and customer programs will also be necessary to incent customers and third parties to actively participate in energy management to optimize the overall efficiency of the grid. For example, customer energy programs proposed through the Energy Efficiency and DR program plans will be coordinated with GMP investments so synergies between grid modernization and customer programs can be realized. Details are provided in *Section 4.3.2 Load Management Programs*.

6. Accountability

National Grid is committed to delivering on grid modernization investments. There are several uncertainties associated with the evolution of the grid that are out of National Grid's control, including the actual pace of customer DER adoption over time and the corresponding system impacts as determined through on-going distribution planning processes, and the evolution of complementary policies and programs. Nevertheless, the Company has created several external and internal measures that will hold us accountable to what is within our control.

Externally, the Company will present project plans for future investments in their appropriate forums at the appropriate time throughout the horizon of the GMP. This iterative process enables on-going engagement and review and reduces risks. The Company fully expects to adapt and adjust its plans considering a number of external factors, including the Load Forecasting Metrics presented below. The Company will also monitor and share Implementation and Performance Metrics based on Company-specific infrastructure deployment metrics and distribution system performance metrics. This information will be provided annually as part of a proposed GMP compliance report that will be shared on the System Data Portal for transparency to all stakeholders. In addition, through the ITR Pilot projects, the Company will continue to engage with the GMP and AMF Subcommittee and participate in grid modernization pilot projects in order to refine the assumed GMP costs, benefits, and implementation plans, so they can be reviewed and adjusted throughout the horizon of the plan.

Internally, transformation focused offices within the Company are responsible for the delivery of large programs and ensuring that accountability and best practices are established and followed. There is also an internal effort underway to educate employees on grid modernization activities. See section 6.3 for details. Overseeing these measures is National Grid's Net Zero by 2050 Plan, in which the Company has developed a framework to achieve net zero GHG emissions by 2050, including emissions that result from the sale of electricity and gas to our customers, by focusing our work in ten areas. One of the ten areas of focus is enabling and optimizing DG by further investing in grid modernization for the benefit of all customers.

6.1. Forums for Regulatory Review

The evolution of a two-way distribution system will impact all elements of the electric business and therefore will be impacted by decisions made in several regulatory forums. The associated Updated AMF Business Case presented in concert with this GMP, is the only element seeking a new or off-cycle review and approval for cost recovery from the PUC.

The deployment of Advanced Field Devices, which are driven by needs identified through distribution planning, will be presented and reviewed as part of annual ISR plans. Investments in the Company's Control Centers and Back Offices, Operational Telecommunications, and Modular Optimizing Applications can usually be leveraged by multiple National Grid subsidiaries, and therefore these systems will generally be owned by the National Grid Service Company. Costs for the usage of these systems by the Company (i.e., The Narragansett Electric Company) will be accounted for as O&M in the form of annual rental fees, and cost recovery will generally be presented and accounted for through periodic general rate case filings. In addition, there are several complementary customer offerings that will enable the cost-effective management of load and DER impacts to the grid, which are not included in this GMP. The stakeholder engagement, program development, and cost recovery review of these programs will likely take place in EE, DR, and SRP proceedings.

6.2. Reporting Metrics

The GMP proposes a flexible and sequenced plan of investments subject to review and adjustment by stakeholders and regulators throughout the GMP's ten-year horizon. By these means, the Company proposes to monitor and report on three sets of metrics on an annual basis throughout the horizon of the GMP to ensure timely and effective solutions are deployed and benefits realized: Load Forecast Metrics, Implementation Metrics, and Performance Metrics. The Implementation and Performance Metrics proposed here are based on the Company-specific infrastructure and Statewide performance metrics that the Company reports on in its Massachusetts affiliate in Docket D.P.U. 15-120.[62] These metrics will be provided annually as part of a proposed GMP compliance report that will be shared on the System Data Portal for transparency to all stakeholders.

Load Forecast Metrics: The scale and timing of the deployment of the many of the grid modernization investments will be driven primarily by needs identified through distribution planning studies and DER interconnection studies, which are based on the Company's load forecast, which is informed by the actual pace of DER penetration over time and DER related policies and programs (e.g., State solar DG programs, Company EV and EHP programs). In order to properly forecast the distribution system load and estimate individual feeder and substation needs, the Company plans to monitor the following metrics on an annual basis throughout the horizon of the GMP. Although these metrics are not driven by the GMP investments, they will be monitored so that the GMP can adapt appropriately to the evolving environment.

[62] *See Petition of Massachusetts Elec. Co. and Nantucket Elec. Co. d/b/a National Grid for Approval by the Dep't of Pub. Util. of its Grid Modernization Plan*, Docket D.P.U. 15-120, Order at 200, 201 (May 10, 2018).

- DER Interconnections (installed and in queue)
  - Wind DG (nameplate kW)
  - Solar DG (nameplate kW)
  - Energy Storage (nameplate kW)
  - EHP Heating Demand (peak load kW)
  - EV Charging Demand (peak load kW)

- Dispatchable DR (available kW and kWh registered and number of dispatch events)
  - Customer DR Programs (i.e., residential, C&I)
  - NWA Projects (e.g., company-owned or contracted third-party DER)
  - Energy Storage (i.e., customer solutions through customer DR programs, NWA, or other means)

Implementation Metrics: In order to ensure grid modernization solutions are deployed according to plan, the Company plans to track the deployment progress of GMP investments by monitoring the following metrics on an annual basis throughout the horizon of the GMP.

- Advanced Field Devices: number of devices installed and in-service, number of feeders covered, cost for deployment, deviation between actual and planned deployment
  - AMF (see Updated AMF Business Case for details)
  - Feeder Monitoring Sensors
  - Advanced Capacitors & Regulators
  - Advanced Reclosers & Breakers

- Control Center and Back Office: number of feeders and substations commissioned/complete, cost for deployment, deviation between actual and planned deployment
  - GIS Data Enhancements
  - ADMS Core Functionality (RTU separations, ADMS load flow models, ADMS/DSCADA control capability)
  - Underlying IT Infrastructure
  - Appropriate Cyber Services

- Operational Telecommunications: number of communication devices, or nodes, or miles of fiber installed, and/or service area coverage; cost for deployment; deviation between actual and planned deployment

- Modular Optimizing Applications: number of feeders commissioned, cost for deployment, deviation between actual and planned deployment
  - VVO/CVR
  - FLISR
  - DERMS

- ITR Pilot Projects: summary of 2-3 ITR topic areas, projects selected, GMP goals and objectives, cost for pilot demonstration, and expected costs and benefits of the fully deployed solution

Performance Metrics: In order to determine if expected grid modernization benefits are being realized, the Company plans to track the performance of GMP investments by monitoring the following metrics on an annual basis throughout the horizon of the GMP.

- System-Level Impacts (Narragansett Electric)
  - Peak Loading (MW, date, time)
  - Minimum Loading (MW, date, time)
  - Load Range (peak – minimum)
  - Load Factor (average / peak)

- AMF (see Updated AMF Business Case for details)
  - Remote Metering: effect on outage notification timing (change before and after AMF commissioning), operational efficiency savings, additional energy and peak demand savings with VVO/CVR
  - Customer Information: energy savings, peak demand savings
  - Advanced Pricing: energy savings, peak demand savings

- Modular Optimizing Applications
  - VVO/CVR: energy savings, peak demand savings, loss reduction, power factor improvement
  - FLISR: number of FLISR operations, effect on outage duration and frequency (SAIFI and SAIDI change before and after FLISR commissioning)
  - DERMS: number of interconnections with capability, capacity factor improvement

6.3. Company Support for Grid Modernization Implementation

The Company and its employees are committed to delivering a clean, reliable, and affordable energy future for customers. In order to execute this vision, the Company has established transformation focused groups that are responsible for delivering large programs like AMF, ADMS, and other grid modernization investments, including ensuring accountability and best practices are established and followed.

The Company has undertaken efforts to enable and educate employees to understand, construct and oversee implementation of grid modernization solutions and technologies. The Company has developed and maintains standards and work methods for dealing with the grid modernization equipment and technology. The Company is also integrating grid modernization into the formal training programs for all employees delivered through our Learning and Development organization. The current approach to training includes both local in-person training and engagement and will be supplemented with video and digital training capabilities. Additional training for Control Center personnel has been planned including ADMS road shows, a sandbox learning environment as well as multi-day training for all users.

In addition, in order to instill support for grid modernization activities across the organization, the Company has evaluated and begun educating all its employees about grid modernization in the following ways:

- Conducted 34 interviews in 16 different business areas across the Company to help ascertain the level of understanding and buy-in from its employees related to its grid modernization efforts.

- Conducted *Change Management Check In* surveys and found favorable agreement with the Company's efforts in its Case for Change, Change Capability, Culture, Resourcing, Sponsorship & Support, and Training Readiness categories based on responses from nearly 800 employees.

  - Rhode Island-based personal had noted more favorable responses in most categories compared to their peers.
  - Increases were seen compared to past surveys in the following areas:

    - Awareness of grid modernization investments and their benefits
    - Awareness of grid modernization being one of the ways National Grid is transforming
    - Engagement for learning about and/or preparing for the company's grid modernization investments

- Developed a Grid Modernization Leadership Video answering questions related to grid modernization. The video is being distributed to all Electric Business Unit (EBU) employees to provide some context and an introduction to grid modernization.

- Launched internal communications including "Grid Modernization Minutes" and "Grid Mod Change Story" as shown in Figure 6.4 below.

  - Grid Modernization Minutes are quick, fun, and bite-size piece of information usually sent via email to all Company employees to educate or communicate updates about the projects or technology.
  - Grid Modernization Change stories act as the anchor for future communications related to grid modernization. The change stories are being widely distributed across the organization, as posters, 3-D table top cubes, emails and videos.

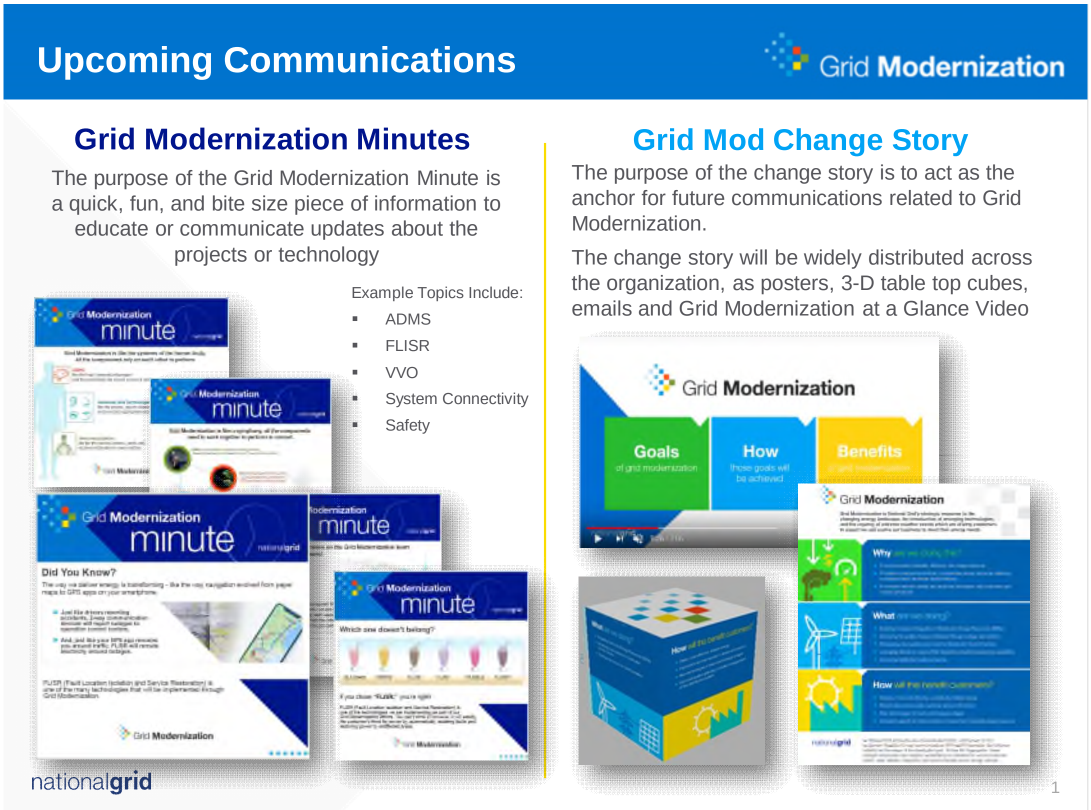

Figure 6.4: Grid Modernization Internal Communications

7. AMF Roadmap and Grid Modernization Integration

The granular, timely energy usage information provided by AMF will empower customers with enhanced understanding, choice, and control over their electricity consumption, enabling customers to reduce energy bills through greater insights about their energy cost drivers, personal usage, and new product and service offerings. AMF data and remote capabilities will also provide support to grid-side applications within the scope of the GMP, increasing operational efficiency, improving customer energy cost reductions, and better supporting the integration of DERs.

As highlighted in the Implementation Plan document, AMF is an integral part of the GMP 2030 Roadmap. While the Implementation Plan summarizes the Company's AMF proposal, costs, benefits and five-year implementation plan, this section highlights how the AMF roadmap and functionalities are critical to achieving GMP objectives. In the Updated AMF Business Case, all functionalities enabled by AMF are categorized in three phases, as described in Table 7.1. The subsequent sub-sections highlight some of these functionalities and how they enable key GMP functionalities.

Table 7.1: AMF Functionalities, Funding and Timeline

Deployment Timeline	Description	Costs and Benefits included in the AMF Business Case?
Near-Term Functionalities Available Upon Deployment	Functionalities enabled by initial AMF implementation; all associated benefits included in Updated AMF Business Case	Yes – All costs and benefits are included in Updated AMF Business Case and the GMP (Full Grid Mod Case) BCAs
Future Functionalities (5-10 years)	Future functionalities in various stages of development and testing by AMF vendors that will require additional evaluation and funding	No – Advanced functionalities are qualitatively discussed in Updated AMF Business Case but costs and benefits are *not* included in either the GMP or AMF BCAs; functionalities would be proposed in future filings if and when they are deemed beneficial to Rhode Island customers
Future Functionalities (>10 years)		

7.1. AMF Near-Term Functionalities

AMF near-term functionalities, available upon deployment of AMF meters, are foundational[63] to achieving three key grid modernization functionalities and provide significant enhancements to six others, allowing for better observability, planning, and control of the distribution system and DERs. The following Table 7.2 is a brief summary of how AMF near-term functionalities are important enablers for most of the key GMP functionalities. Please see the Updated AMF Business Case for a full list and descriptions of AMF-enabled functionalities.

[63] Foundational means the GMP functionality would not be possible without AMF.

Table 7.2: AMF Near-Term Functionalities & Impact on RI GMP Functionalities

RI GMP Key Functionality	AMF Near Term Enabling Functionality	AMF Impact on GMP Functionality
Customer Information	CEMP, GBC, Integration w/ In-Home Technologies	Foundational
Advanced Pricing	Interval Energy Usage Data	Foundational
Remote Metering	Remote Interval Meter Reading, Remote Connect & Disconnect	Foundational
Observability (Monitoring & Sensing)	Load & Voltage Data	Enhancement
Power Quality Management	Load & Voltage Data	Enhancement
Distribution Grid Control	Load & Voltage Data	Enhancement
Grid Optimization	Load & Voltage Data	Enhancement
Reliability Management	Automated Outage & Restoration Notification, Granular Fault Location	Enhancement
DER Operational Control	Remote Interval Meter Reading, Load & Voltage Data, Operational Telecommunications (Tier 3)	Enhancement

Further detail related to AMF impacts on GMP functionalities is included below:

- **Customer Information:** The Company's AMF solution proposal provides access to timely, granular energy usage information for all customer classes through three primary channels: 1) CEMP through web and mobile devices, 2) GBC that will be accessible from the CEMP, and 3) directly from the meter in real-time through a home-area-network (HAN). AMF also empowers customers to reduce their energy costs using enhanced insights (such as high bill alerts) on more granular, timely energy usage data through the CEMP or using integration with in-home technology.

- **Advanced Pricing:** AMF provides customer and DER level interval energy usage information required to support TVR and customer load management programs that can be used to shift energy consumption between time periods to reduce energy costs and/or alleviate location specific constraints on the delivery system.

- **Remote Metering:** AMF improves operational efficiency by enabling the Company to eliminate O&M costs associated with AMR meter reading, investigations and visits to connect and disconnect service.

- **Observability (Monitoring & Sensing):** AMF provides granular and timely customer load data to support actionable information on the operating state and condition of the distribution grid and DER assets necessary for safe, secure, and reliable operation.

- **Power Quality Management:** An incremental 1% VVO/CVR-based reduction in energy and peak demand is expected to be achieved by integrating granular AMF voltage data into the VVO control schemes due to better awareness of feeder voltages compared to using only voltage data from Advanced Field Devices.

- **Distribution Grid Control:** Granular and timely customer load data from AMF supports more accurate load flow calculations, enabling the system operator to rearrange the distribution feeders and maximize load-to-generation balance to avoided thermal issues.

- **Grid Optimization:** AMF provides granular customer load data from interval power monitoring at the customer level, which provides a step change in available data for grid planning and operations. While the latency of AMF data is not the same as operational SCADA data from Advanced Field Devices, appropriate analytics of the AMF data will significantly improve the load flow models used by distribution planners and within the proposed ADMS for distribution system operators. Today, feeder level data combined with generic load shape analysis is used to model remote end feeder performance. AMF provides more granular data that can be aligned with other system data to create actual loading and voltage profiles at all points along a feeder. This complete data set can be modeled directly and more detailed load and DER forecasts can be developed for planning and operational needs.

- **Reliability Management:** AMF provides autonomous outage notifications, alerting the Company to trouble before receiving customer outage calls. Integrating this functionality with the Company's OMS (via an ADMS) will reduce time from initial outage to Company notification, and enhance the Company's overall outage response capabilities. AMF also provides restoration notifications enabling the Company to verify whether power has been restored to all meters, reducing the need for crews to verify restoration and alerting the Company if some meters are still out of power. In addition, AMF provides granular outage data at the customer level, increasing the accuracy of fault location capabilities of an ADMS. More accurate fault location improves operational efficiency through a reduction in field crew hours and vehicle miles traveled, and it improves the isolation and restoration capabilities of FLISR.

- **DER Operational Control:** AMF supports DER optimization by providing the interval energy and voltage data at the customer level required for verification and settlement of DER services provided to or received from the grid. AMF also enables the exchange of information and/or control with all residential and small commercial (<25 kW) DER technologies through AMF's investment in a Tier 3 (FAN) operational telecommunications, which would not be possible without AMF investment.[64] The use of

[64] Currently, the Company requires a dedicated phone line, RTU, and interval meter for all distributed generation greater than 25 kW, but there are not meter requirements for systems smaller than 25 kW.

this data by outside parties will be subject to the Data Governance Plan, which is part of the Updated AMF Business Case filing.

7.2. AMF-Enabled Future Functionalities

A key design attribute of the AMF solution is the flexibility and adaptability of the solution to meet evolving customer and grid needs. The solution the Company is implementing represents the latest generation of maturing AMF technology[65] where the solution capabilities include over-the-air firmware upgrades and grid-edge computing platform capabilities, supporting software applications that are deployable to the meters for both grid- and customer-facing use cases.

The Company believes the grid-edge computing platform will enable a number of additional future functionalities that build on the near-term functionalities. Table 7.3 describes some of the AMF functionalities that the Company believes could be evaluated in 5-10 years and those that could be evaluated 10 years and beyond, and how they would integrate with and enhance other grid modernization functionalities. Note however, that costs and benefits of these advanced functionalities are not estimated or included in either the GMP or AMF quantitative BCAs. Additional AMF-enabled future functionalities are described in greater detail in *Section 5.3: Roadmap for AMF-Enabled Functionalities* of the Updated AMF Business Case filing.

Table 7.3: AMF Future Functionalities and RI GMP Functionalities

RI GMP Key Functionality	AMF Future Enhancing Functionality	Functionality Description
Observability (Monitoring and Sensing)	Grid Mapping / Locational Awareness	Allows meters to define their location at the transformer- and feeder-level to better collate GIS data while providing better insights to load forecasting, voltage and outage management systems.
Power Quality Management	Intelligent Voltage Monitoring	Enables voltages on the distribution network to be analyzed at the meter level, which can be used to optimize the asset life of transformers while ensuring power delivery at acceptable voltage ranges and power quality standards. Exceptions are reported.
Reliability Management	Distributed Outage Detection	Supports service restoration using analytics at the meter to identify power on/off signals along with voltage data to quantify power outages for segments of the distribution system, which are then integrated into an OMS to support service restoration.
DER Operational Control	Active Demand Response	Allows autonomous management locally and intelligently by integrating customers with HAN devices to support DR in accordance with utility demand events. Integration with EV charging stations can provide additional DR benefits while facilitating BE.

65 Gartner Report, *Hype Cycle for Smart Grid Technologies* (2017).

7.3. Additional AMF Synergies with the GMP

In addition to playing an integral role in enabling key GMP functionalities and achieving GMP objectives, AMF implementation provides considerable cost synergies and additional benefits to the overall GMP roadmap. First, the ability of AMF to provide granular load and voltage data enables the GMP deployment of Feeder Monitoring Sensors to be reduced by 67%.[66] Second, AMF implementation requires some of the same Underlying IT Infrastructure, Cyber Services, and Network Management investments that are also critical to support other GMP objectives. Thus, AMF implementation creates the opportunity for additional benefits that can build off these foundational GMP investments. Additional details including a comparison of quantified costs and benefits of a case without AMF (i.e., Grid Mod Only Case) and a case with AMF (i.e., Full Grid Mod Case) are provided in *Section 8: BCA Evaluation Under Docket No. 4600*.

8. BCA Evaluation Under Docket No. 4600

This section presents a comprehensive BCA consistent with the PUC's written Report and Order in Docket No. 4600 and the PUC's Guidance Document.[67] In its Report and Order in Docket No. 4600, the PUC held that the 4600 Framework should serve as a starting point in making a business case for a proposal and should not be the exclusive measure of whether a specific proposal should be approved. The PUC recognized that there may be outside factors that need to be considered regardless of whether a specific proposal is determined to be cost-effective or not, such as statutory mandates or qualitative considerations, and that such application is consistent with the PUC's broad regulatory authority in setting just and reasonable rates. Therefore, the BCA presented here uses the 4600 Framework to evaluate the cost-effectiveness of investments in grid modernization.

8.1. Approach

The GMP BCA follows the following key principles to assess the cost-effectiveness of the grid modernization portfolio:

- Counterfactual Treatment: Future grid modernization investments are compared to the Reference Case in a consistent and comprehensive manner.
- Energy Policy Goals: To the extent possible, the BCA accounts for Rhode Island's various policy goals. In particular, the High DER scenario assumes a future state that is consistent with the Resilient Rhode Island Act's 80x50 Goal.
- Symmetry: BCA includes all quantifiable costs and benefits for each investment.

[66] This avoided sensor cost is included as an AMF benefit in the AMF BCA.
[67] *See* Docket 4600 Guidance Document, *supra* note 9.

- Forward Looking: BCA captures costs and benefits of the ten-year GMP portfolio of solutions over the assumed 20-year life of the grid modernization investments, disregarding sunk costs and benefits.

To ensure the BCA covered all the potential benefits and costs introduced by grid modernization investments, the Company surveyed several other utility filings for AMF and grid modernization plans to understand the scope of the BCA (i.e., which grid modernization functionalities and investments were included) as well as the type of cost-effectiveness test that was being applied (e.g., least-cost/best fit, societal cost test). This survey also provided a benchmark for benefit and cost categories to be included in the Company's grid modernization BCA. The results of the survey are included in Attachment B, the Appendix and show that the scope and breadth of the Company's BCA for Rhode Island is more thorough than the other filings in the survey as a result of the Company having applied the Docket No. 4600 Framework and detailed modeling of a future distribution system in Rhode Island. Details for Dayton Power and Light's (DP&L) Grid Modernization Plan and Xcel Energy's Integrated Distribution Plan, the only other filings in the survey that performed stand-alone quantitative BCA for grid modernization solutions without AMF, are also presented in Attachment B, the Appendix.

Due to the significant customer benefits enabled by AMF, and because the Company has a separate AMF filing, two separate, but consistent, quantitative BCA models were developed: GMP BCA model and an incremental AMF BCA model. The GMP BCA model assumptions and results are described in detail in this section and the AMF BCA is described in detail in the Updated AMF Business Case filing. The following key assumptions are used in the base case BCAs for both the GMP and AMF:

- Nominal Discount Rate = 6.97% (After-Tax WACC)
- Labor Escalation = 3.00%
- Non-Labor Escalation = 2.26%

Because the GMP and AMF BCA models used a consistent approach and input assumptions, the results of the two BCA models can be combined to show the overall grid modernization portfolio benefits and costs (i.e., Full Grid Mod Case). However, the detailed BCA assumptions and results presented in this section are focused on the GMP BCA model (i.e., Grid Mod Only Case).

8.2. Alternatives Evaluation

The Company's BCA considers two different customer DER adoption scenarios and two different grid modernization deployment cases, resulting in four alternatives evaluated. These are summarized in Table 7.1. The Low and High DER adoption scenarios are used to evaluate the range of impacts the Company could expect on the distribution system in the future due to customer adoption of DERs. The Grid Mod Only and Full Grid Mod deployment cases are meant to highlight the contribution of AMF to the cost-effectiveness of the entire grid modernization portfolio of solutions. Each scenario is compared to a Reference Case, in which no grid modernization measures are deployed and only traditional solutions are used to interconnect DG, accommodate BE, transmit only monthly customer energy information, and communicate with customers as is generally done today. The benefits calculated in the BCA are a direct result of the new capabilities and functionalities enabled by grid modernization investments compared to the "traditional" solutions assumed in the Reference Case.

The two grid modernization deployment cases are:

- **Grid Modernization Solutions without AMF (Grid Mod Only Case):** assumes grid modernization solutions without AMF are used to integrate DG and enable customer energy savings and reliability improvements

- **Full Grid Modernization Solutions including AMF (Full Grid Mod Case):** assumes grid modernization solutions including AMF with TVR are used to integrate both DG and BE (e.g., EV charging optimization using load shifting) and enable customer energy savings, reliability improvements, increased customer choice and control, and a better customer experience

The two customer DER adoption scenarios are summarized below. Details are presented in *Section 3.2: Future State Scenarios*.

- **Low DER Scenario:** Conservative adoption of renewable DG, EVs and EHPs based on historic (2018-2020) DER adoption rates with an annual reduction in renewable DG adoption over time

- **High DER Scenario**: Higher adoption of a range of DER technologies including renewable DG, EV and EHP consistent with achieving Rhode Island's 2050 goal of 80% greenhouse gas emissions reductions compared to a 1990 baseline

Together, these two DER scenarios "bookend" the range of issues the Company will likely encounter on the distribution system in the future and are therefore used as the two scenarios for the Company's BCA. The scope of the BCA is limited to utility investments - therefore, the results are not intended to evaluate whether the potential DER adoption scenarios or policy targets themselves are cost effective. Importantly, the BCA does not include environmental or other benefits (or costs) associated with future DER deployments (i.e., GHG emissions reduction due to an increase in renewable DG adoption) compared to today. These benefits (and costs) compared to today would be accounted for by the individual DER programs or policies that are developed to achieve the deployment levels assumed.

The combination of the two grid modernization cases deployed under two DER adoption scenarios results in four alternatives to be compared with a Reference Case, as shown in Table 8.1.

Table 8.1: Grid Modernization Evaluation of Alternatives Matrix

Grid Modernization Alternatives	Low DER Scenario	High DER Scenario
Grid Mod Only Case (without AMF)	Grid Mod Only solutions without AMF (AMR only) and lower adoption of DERs	Grid Mod Only solutions without AMF (AMR only) and higher adoption of DERs
Full Grid Mod Case (with AMF)	Full Grid Mod solutions including AMF and lower adoption of DERs	Full Grid Mod solutions including AMF and higher adoption of DERs

Within each scenario (Low DER or High DER), the customer DER adoption assumptions are consistent, regardless of what assumptions are made regarding grid modernization deployment. However, the deployed grid modernization technologies, programs, and policies will be different in the Reference Case, Grid Mod Only Case, and Full Grid Mod Case, as presented in Table 8.2.

Table 8.2: 2030 Future State Assumptions

Future State Assumptions	Reference Case	Grid Mod Only Case	Full Grid Mod Case
Customer DER Adoption	Same across all cases for given scenario (Low DER or High DER)		
Grid Infrastructure Technology	Traditional Solutions[68]	Grid Modernization Solutions	Grid Modernization Solutions
Metering Technology	AMR	AMR	AMF
Customer Load Management Programs	Existing Energy Efficiency & DR, System Data Portal	Future Energy Efficiency & DR, System Data Portal, NWA	Future Energy Efficiency & DR, System Data Portal, NWA, BE with TVR, and new programs unlocked by AMF[69]
DG Policies and Programs	Existing Electric Service Bulletin (ESB), Seasonal Curtailment	Updated ESB, Flexible Interconnection Standards, Smart Inverters, Granular Curtailment	Updated ESB, Flexible Interconnection Standards, Smart Inverters, Granular Curtailment, AMF for small-scale DER
Rate Policies and Programs	NEM, monthly energy billing	New DG Tariffs for large-scale DER	New DG Tariffs for large- and small-scale DER, TVR

A fair comparison of the grid modernization investments to the counterfactual case without grid modernization (i.e., Reference Case) requires customer DER adoption be an exogenous variable in the GMP BCA. Therefore, the Company did not attempt to estimate the difference in the

[68] Traditional solutions include line reconductoring or installing new feeders and new conductor routes, but also includes field devices, like capacitors, regulators, and reclosers to accommodate increasing levels of DG.
[69] Such new programs unlocked by AMF in the Full Grid Mod Case could include: targeted customer engagement, behavioral Energy Efficiency & DR/pay for performance programs, new evaluation, measurement & valuation (EM&V) options, and eventually perhaps remote home energy audits and continuous whole home/business energy optimization programs.

amount of renewable DG that could be interconnected in the grid modernization cases compared to the Reference Case, where many DG projects are likely to be uneconomic by 2030 under the High DER Scenario (see State-Level Analysis section for details). Instead, the Company quantified the value of enabling greater DER integration using two of the benefit categories summarized in *Section 8.3: Avoided D-System Infrastructure Cost*:

- Avoided Distribution System (D-System) Infrastructure Cost benefit based on the difference between the estimated traditional infrastructure upgrade costs necessary to accommodate future DG interconnections in the Reference Case compared to the grid modernization cases

- Reduced DG Curtailment benefit based on the difference between the estimated seasonal curtailment in the Reference Case and the optimized power output (i.e., granular curtailment) that is possible in the grid modernization cases

8.3. Benefit Impacts

For the purposes of estimating power system, customer, and societal benefits that are aligned with each GMP goal, the Company developed several benefit impact areas, which are quantified in the BCA. Each quantified benefit impact area has been aligned with a particular GMP goal in Table 8.3.

Table 8.3: Alignment Between Rhode Island GMP Goals and Quantified Benefit Impacts

RI GMP Goal	Benefit Impact Area
1) Give customers more energy choices and information	Improved Customer Choice & Control
	Improved DER Experience
	More Equitable Cost Allocation
	More Equitable Benefit Allocation
2) Ensure reliable, safe, clean, and affordable energy to benefit Rhode Island customers over the long term	OPEX Labor Efficiency
	Avoided Legacy OPEX Investments
	Avoided Legacy CAPEX Investments
	Reduced Customer Energy Use
	Reduced System Capacity Requirements
	Reduced Outage Notification Time
	Reduced Outage Restoration Time
3) Build a flexible grid to integrate more clean energy generation	Avoided D-System Infrastructure Cost
	Reduced DG Curtailment

Each benefit impact area has been defined and categorized based on the GMP and AMF benefit categories below.

Avoided O&M Costs

- OPEX Labor Efficiency: Improvements in operational efficiency, such as eliminating AMR meter reading, or reducing meter investigations and visits to connect and disconnect service.

- Avoided Legacy OPEX Investments: Avoiding "legacy" OPEX system investments, including RTB telecoms costs from existing Advanced Field Devices and future DERs, due to the proposed grid modernization investments.

Avoided Capital Costs

- Avoided Legacy CAPEX Investments: Avoiding "legacy" CAPEX system investments, such as AMR hardware replacement and installation costs, due to the proposed grid modernization investments.

- Avoided D-System Infrastructure Cost: Improvements in load optimization due to the ability of the system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs, rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption.

Customer Benefits - Empowerment

- Improved Customer Choice & Control: Improvements in customer energy usage information sharing, third party information sharing, and access to third party service providers, which empowers customers to better understand and prioritize among solutions to best manage energy usage and costs.

- Improved DER Experience: Improvements that enable an improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes, flexible interconnection options, reductions in time to interconnect, and better customer and third-party information sharing and services.

- More Equitable Cost Allocation: Improvements in the ability to allocate costs to different classes of customers in a way that more precisely reflects their respective contributions to system-level costs and will support development of more cost-reflective rates and pricing that limit cross-subsidization.[70]

- More Equitable Benefit Allocation: Improvements in the ability to allocate benefits to compensate customer- or third-party owned DERs in a way that is more reflective of actual system benefits (e.g., shift from current net energy metering programs to location- and market-based DER pricing).

Customer Benefits – Energy Savings

- Reduced Customer Energy Use: Reductions in electrical energy used by a customer, which can be a result of customer action based on enhanced energy use insights (e.g., AMF-based High Bill Alerts) or integrating AMF with in-home technologies; or utility action, such as operating distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption from customer appliances (e.g., VVO/CVR).

- Reduced System Capacity Requirements: Reductions in system capacity requirements in either the generation, transmission or distribution systems, which can be a result of customer action based on enhanced energy use insights (e.g., AMI-based High Bill Alerts), integrating AMF with in-home technologies, or responding to TVR to reduce demand for energy during peak demand periods; or utility action, such as operating distribution feeders at lower overall voltages (within ANSI limits) to reduce peak demand from customer appliances (e.g., VVO/CVR).

Customer Benefits – Reliability Improvements

- Reduced Outage Notification Time: Reductions in customer outage notification time due to AMF remote metering and the ability of the system operator to quickly identify an outage and reconfigure the system rather than waiting for phone calls from customers to identify an outage.

- Reduced Outage Restoration Time:[71] Reductions in customer outage durations due to the ability of the system operator and control system to quickly generate switch orders (i.e., ADMS-based SOM) or locate and isolate a fault and restore power (e.g., FLISR) rather than waiting for field crews to locate and restore power.

[70] It is important to note that achievement of certain outcomes to more equitable cost or benefit allocation may require both the more granular customer and system information supported by GMP as well as additional regulatory and/or legislative activity.
[71] This benefit is based on sustained outages (as opposed to momentary outages), which are defined as lasting longer than 5 minutes.

Customer Benefits – Avoided Bulk Energy Purchases

- Reduced DG Curtailment: Reductions in DG curtailment during the interconnection application stage or during operations due to the ability of the system operator to manage DERs and optimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints.

Societal Benefits

- Reduced Customer Energy Use: Reductions in non-embedded central power plant emissions of CO_2, SO_2, and NO_x resulting from reductions in electrical energy used by a customer, which can be a result of customer action (e.g., AMF-based High Bill Alerts) or utility action (e.g., VVO/CVR).

- Reduced DG Curtailment: Reductions in non-embedded central power plant emissions of CO_2, SO_2, and NO_x resulting from the ability of the system operator to manage DERs and optimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints.

Additional qualitative benefit impact areas were identified and categorized based on the GMP benefit categories in Table 8.4. Each of the qualitative benefits and their drivers are described in *Section 8.6: Qualitative Assessment*. These benefits will continue to be evaluated and could be quantified in future BCA results as additional data and methods are developed.

Table 8.4: Rhode Island GMP Qualified Benefits and Drivers

Grid Modernization Qualitative Benefits and Drivers		
GMP Benefit Category	**Benefit Impact Area**	**Benefit Driver**
Avoided O&M Costs	OPEX Labor Efficiency	OpTel Network Refresh
	Avoided Legacy OPEX Investments	Flexible OpTel Network
	Improved Long-Term Forecasting for Planning	Granular Data
	Improved Operational Efficiency	Granular Data
		Mobile Dispatch
		Protection Coordination
Customer Benefits – Empowerment	Improved Customer Choice and Control	Customer Information Sharing
	Improved DER Experience	DER Integration
	More Equitably Cost Allocation	Granular Data
	More Equitably Benefit Allocation	Granular Data
Customer Benefits – Energy Savings	Reduced Customer Energy Use	Network Model Integration
	Reduced Customer Energy Costs	Enhanced Load Shift
	Improved Short-Term Forecasting for Operations	Granular Data
	Reduced System Loss	Local Generation Sources
		Optimized Reactive Power Control
Customer Benefits – Reliability Improvements	Reduced Customer Outages	Granular Data
		OpTel Network Refresh
	Improved Restoration Times	Mobile Dispatch
	Improved Storm Recovery	Granular Data and Distributed Automation
	Improved Resilience	Situational Awareness and Distributed Automation
	Improved Customer Satisfaction	Outage Notification
	Grid Modernization Performance Benefits	Reliable OpTel Private Network
Societal Benefits	Economic and Environmental Benefits	DER Integration
	Reduced Damage from Wide-scale Blackouts	Situational Awareness
	Improved Grid Stability and Data Protection	Cyber Security

8.4. Quantitative Benefit-Cost Analysis

The grid modernization BCA uses the Rhode Island Test framework, as established by Docket No. 4600, to identify where grid modernization solutions contribute to specific cost or benefit categories. Where possible, these benefits are quantified. In cases where benefits cannot be quantified due either to lack of data or lack of accepted method, the Company conducted a qualitative analysis of the benefits, consistent with the Docket No. 4600 Framework. qualitative explanation of benefits is provided in *Section 8.6: Qualitative Assessment*.

As described in *Section 5.5 Functionality and Benefit Impacts Assessment*, many of the functionalities and benefits available through the GMP occur when multiple solutions interact. This increases the challenge for stakeholders and decision-makers who would like to consider GMP solutions on an individual solution basis. In general, the overall GMP benefit-cost ratio (BCR) is presented in terms of the full portfolio of inter-related investments. However, to accommodate stakeholder's interest in incremental AMF BCA results, the GMP has evaluated two separate grid modernization deployment cases (i.e., Full Grid Mod and Grid Mod Only) to evaluate the incremental impact of AMF.

8.4.1. Summary BCA Results

A summary of the quantitative BCA results is shown in Figure 8.1 for the Full Grid Mod and Grid Mod Only cases. The blue bar in each scenario represents the costs of deploying the grid modernization program portfolio, and the orange bar represents the quantified benefits of the program. The High DER and Low DER scenarios are intended to bookend the range of costs and benefits based on uncertain future customer DER adoption levels. The Full Grid Mod Case results are based on the AMF BCA model results for the AMF "base case" (i.e., Opt Out, Mid Results, RI+NY Deployment) option. Details are provided in the Updated AMF Business Case filing.

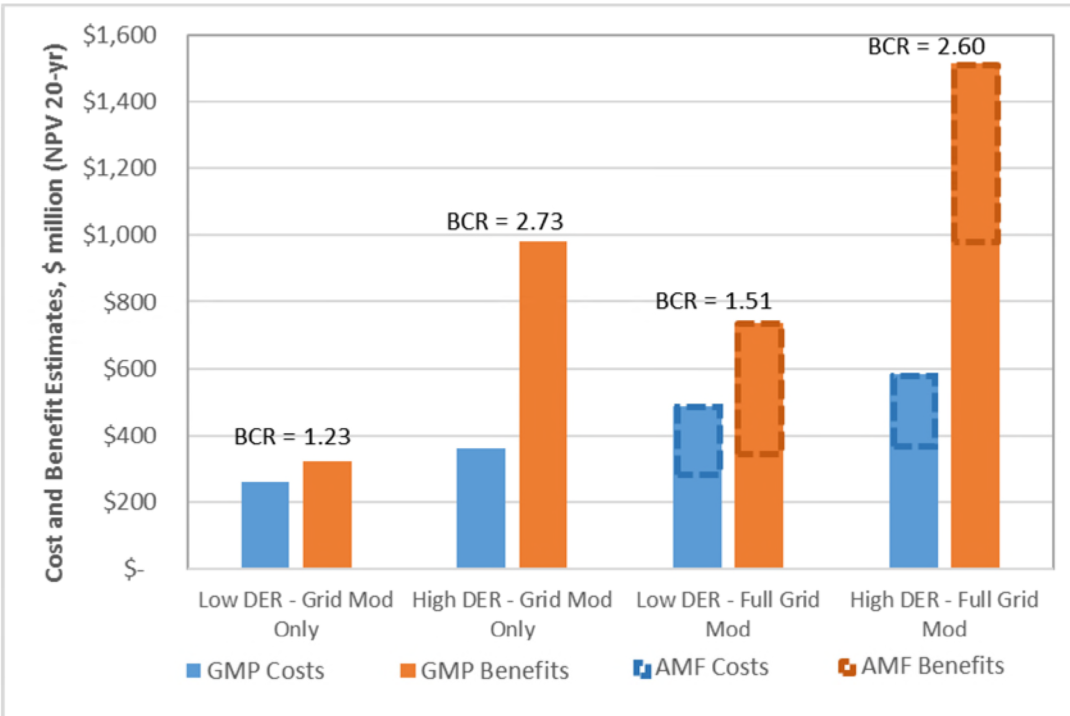

Figure 8.1: Summary of BCA Estimates for all Grid Modernization Cases and DER Adoption Scenarios[72]

The strong correlation of BCA results with DER customer adoption is to be expected since many of the non-AMF investments in the GMP (i.e., Advanced Field Devices) are assumed to be deployed to safely and reliably integrate and manage DER growth. The Company assumes a slower adoption of DERs in the Low DER scenario will drive a slower deployment of Advanced Field Devices each year, while in the High DER scenario, the deployment of Advanced Field Devices is increased rapidly to address the larger number of system issues expected to be caused by the higher DER adoption. In this way, the Company can avoid significant "traditional solution" costs in addition to realizing additional customer benefits, like VVO/CVR-based customer energy savings and FLISR-based reliability benefits. Therefore, benefits are larger in the High DER Scenario due to the larger avoided traditional solution costs as well as the larger number of customers benefiting from grid modernization.

Note that additional benefits described in *Section 8.5: Sensitivity Analysis* and *Section 8.6: Qualitative Discussion* are also significant.

The quantified cost and benefit results for each case are summarized below for both the Low DER and High DER customer adoption scenarios:

[72] The Full Grid Mod Case results are based on the AMF benefits and costs for the AMF "base case" (i.e., Opt Out, Mid Results, RI+NY Deployment) option.

- **Full Grid Mod Case:** There is a significant variation in the BCA results depending on the assumed level of customer DER adoption. High DER Scenario costs are 20% higher and benefits are 106% higher than the Low DER Scenario. The resulting BCR estimates are 1.51 for the Low DER Scenario and 2.60 for the High DER Scenario (71% increase). Importantly, both DER adoption scenarios result in BCRs that are much greater than one, meaning the benefits significantly outweigh the costs for the Full Grid Mod Case.

- **Grid Mod Only Case:** The BCA results for the Grid Mod Only deployment case also varied for each DER adoption scenario. High DER Scenario costs are 37% higher and benefits are 204% higher than the Low DER Scenario. The resulting BCR estimates are 1.23 for the Low DER Scenario and 2.73 for the High DER Scenario (122% increase). In this case, both DER adoption scenarios result in BCRs that are greater than one, although the Low DER BCR is closer to one than the Full Grid Mod Case (with AMF).

- **Incremental AMF:** The benefits of incremental AMF investment, which are shown as the difference in benefits between the Full Grid Mod and Grid Mod Only cases in Figure 8.1, are large under both DER adoption scenarios, but they are particularly significant under the Low DER Scenario, where AMF benefits increase the GMP net benefits from $61 million to $250 million (NPV 20-year) and the BCR increases from 1.23 to 1.51. In other words, AMF increases the GMP's net benefits under a wide range of customer DER adoption scenarios due to enhancements to grid-side benefits and enablement of customer-side benefits that would not be possible without AMF.

Alternative BCA Formulations

The effect of alternative BCA formulations for a range of key input assumptions is shown in Table 8.4. These sensitivities all produce BCRs greater than 1 with some as high as 3.95 (i.e., "Grid Mod Only – High DER – Economic Development Included"). Also, note that both "Enhanced Load Shift Included" and "DG Curtailment Benefit Excluded" have no effect on the Low DER Scenario because renewable DG curtailment is not projected to be necessary in that scenario.

Table 8.4: Summary of Benefit-Cost Ratios for Alternative BCA Formulations

Grid Mod Alternative Formulation Benefit-Cost Ratios	Full Grid Mod Case		Grid Mod Only Case	
	Low DER	High DER	Low DER	High DER
Base Case	1.51	2.60	1.23	2.73
Economic Development Included	2.06	3.55	1.81	3.95
ROP DRIPE Included	2.25	3.61	1.64	3.44
Societal Discount Rate	1.75	2.97	1.37	2.99
Enhanced Load Shift Included	1.51	2.66	1.23	2.84
DG Curtailment Excluded	1.51	2.00	1.23	1.77
FLISR SAIFI Excluded	1.41	2.47	1.04	2.52

Annual Costs and Benefits

Estimated annual costs and benefits are shown in Figure 8.2 for the "Grid Mod Only – High DER" case. Most costs occur throughout the program based on deployment schedules developed by the Company for each grid modernization solution. Note that these costs include the revenue requirement for capital investments in Advanced Field Devices. The revenue requirement cost contribution continues through FY41, even though Advanced Field Device deployment ends in FY31. Most benefits occur in the later years due to steady deployment of grid modernization and its associated benefits compared to the Reference Case as DER adoption progresses. Simple payback, or the length of time an investment reaches a break-even point, is estimated to be achieved in less than six years based on the quantified costs and benefits included in this GMP.

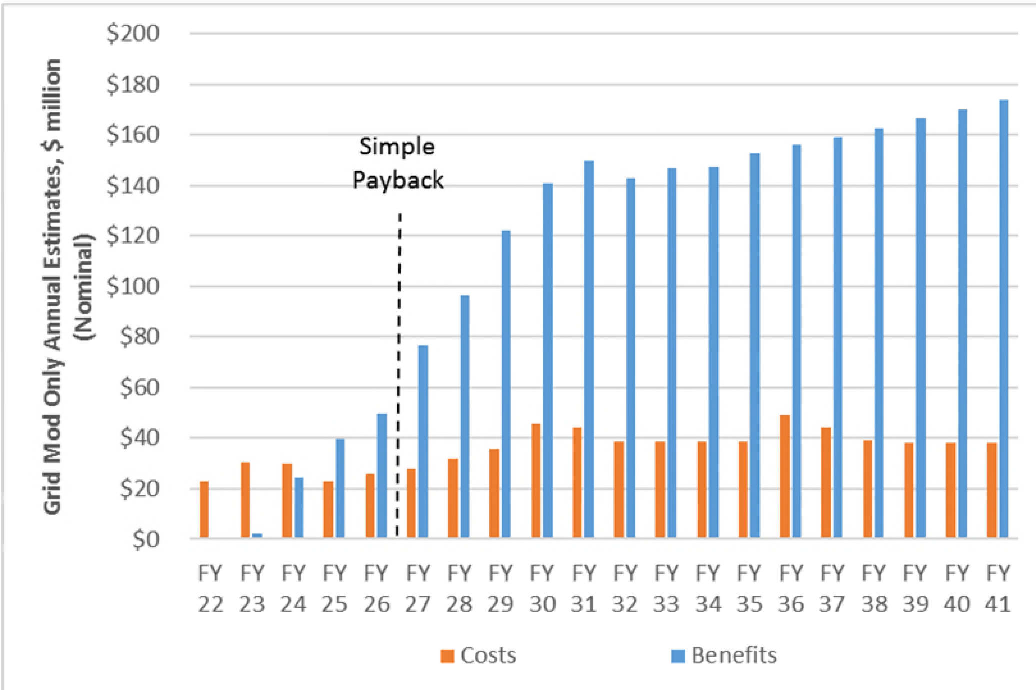

Figure 8.2: Annual BCA Results for Grid Mod Only Deployment and High DER Adoption

Annual results for the Low DER scenario are presented in Attachment B, the Appendix. All cost and benefit results are described in more detail in *Section 8.4.2 Cost Estimation* and *Section 8.4.3: Benefit Estimation.*

8.4.2. Cost Estimation

The Company developed cost estimates for all solutions included in the GMP for both Grid Mod Only and Full Grid Mod deployment cases under both the Low DER and High DER scenarios. The cost estimates used in the BCA include all costs incurred to deploy and maintain the grid modernization investments through the end of the BCA evaluation period, including capital expenditures (CAPEX), operating expenditures (OPEX), and run-the-business (RTB) costs for all solutions presented in the GMP roadmap. Each of these types of cost is described below.

- Capital Expenditures (CAPEX): Labor and non-labor costs related to system specification, design, testing, equipment and software purchase, installation, and cost of removal

- Operating Expenditures (OPEX): Typically, labor costs related to strategic work (e.g., develop roadmaps, research alternative business systems), evaluation and selection of alternatives, vendor selection, and training

- Run the Business (RTB): A type of OPEX that typically extends beyond the plant-in-service or go-live date for the investment, and includes on-going support (e.g., administrative, G&A overhead), software maintenance fees, monthly cellular service fees, and equipment maintenance

Table 8.5 summarizes the cost categories and associated grid modernization solution investments for each category.

Table 8.5: Grid Modernization Cost Categories and Solutions

GMP Cost Category	GMP Solutions
Customer Enablement	• AMF Meter and Installation (i.e., AMF Meters) • System Data Portal
Advanced Field Devices	• Feeder Monitoring Sensors • Advanced Capacitors & Regulators • Advanced Reclosers & Breakers
Control Center and Back Office	• AMF Customer Systems including billing and a CEMP (i.e., AMF Customer Systems) • AMF Platform and Ongoing IT Operations (i.e., AMF Platform & IT Operations) • GIS Data Enhancements • ADMS Core Functionality • Protection & Arc Flash App (ADMS) • Underlying IT infrastructure • Appropriate Cyber Services
Telecommunications	• AMF Communications Network Equipment and Installation (i.e., AMF Communications Network) • Network Management (INOC, TOMS) • OpTel Strategy
Modular Optimizing Applications	• VVO/CVR (existing and ADMS-integrated platforms) • FLISR App (ADMS) • DERMS • ITR Pilot Projects

Cost estimates for the Full Grid Mod and Grid Mod Only deployment cases are summarized in Figures 8.3 and 8.4. As can be seen, most cost categories are similar in each grid modernization case, regardless of DER adoption scenario. This is because there are certain fixed costs with solutions deployed for any level of DER adoption. However, Advanced Field Device costs increase significantly from the Low DER to the High DER scenario due to the assumed increased device deployment with greater DER adoption.

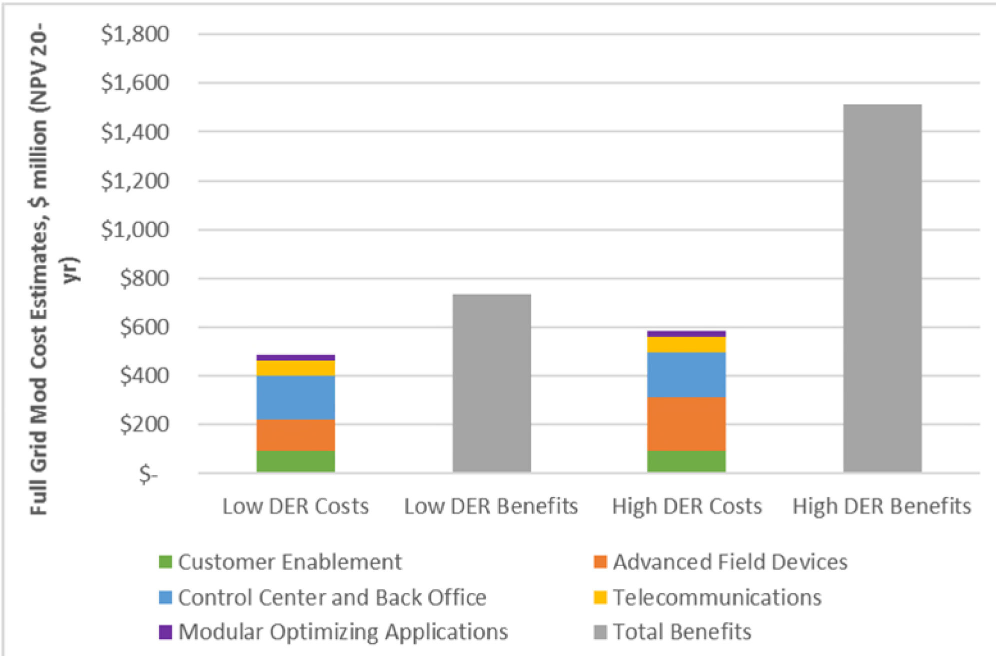

Figure 8.3: Cost Estimates for Full Grid Mod Case

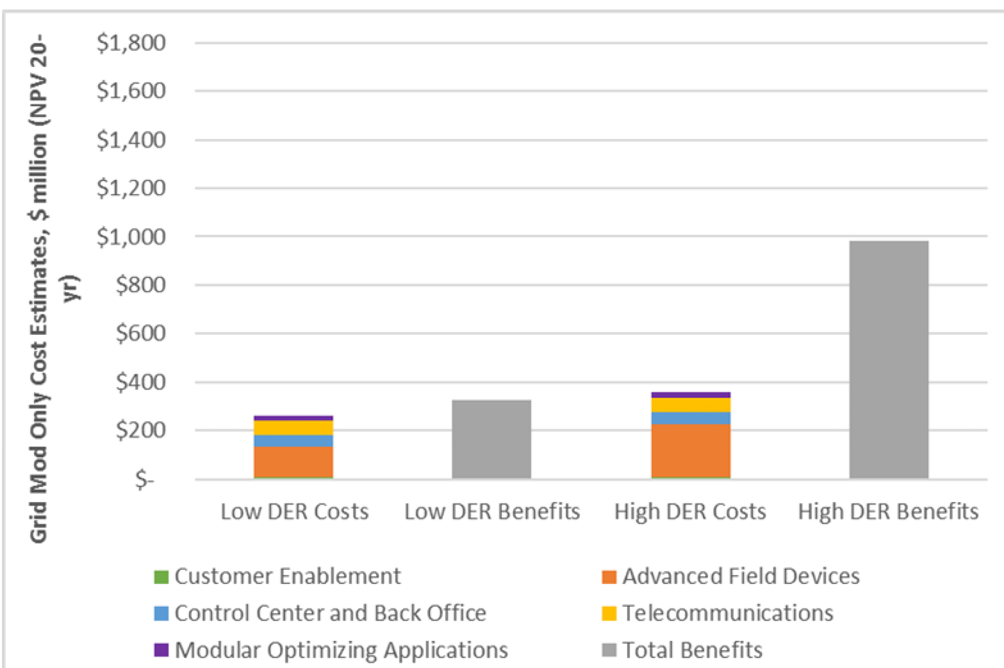

Figure 8.4: Cost Estimates for Grid Mod Only Case

Cost estimates for each GMP investment are presented in Table 8.6. The major investments for the Full Grid Mod Case are AMF Meters, AMF Customer Systems, AMF Platform & IT Operations, Advanced Reclosers & Breakers, and Advanced Capacitors & Regulators. For the Grid Mod Only Case, OpTel Strategy, ADMS Core Functionality, and Feeder Monitoring Sensors are additional cost drivers. The top five cost drivers for each case-scenario combination represent between about 70-80% of the total costs.

Table 8.6: Cost Estimates for All Cases and Scenarios

Grid Mod Cost Estimates, $ million (NPV 20-yr)	Full Grid Mod Case		Grid Mod Only Case	
	Low DER	High DER	Low DER	High DER
AMF Meters	$ 86.01	$ 86.01	$ -	$ -
AMF Customer Systems	$ 59.41	$ 59.41	$ -	$ -
AMF Platform & IT Operations	$ 74.46	$ 74.46	$ -	$ -
AMF Communications Network	$ 3.80	$ 3.80	$ -	$ -
System Data Portal	$ 9.64	$ 9.64	$ 9.64	$ 9.64
Feeder Monitoring Sensors*	$ 17.45	$ 30.81	$ 17.45	$ 30.81
Advanced Capacitors & Regulators	$ 55.08	$ 96.85	$ 55.08	$ 96.85
Advanced Reclosers & Breakers	$ 50.94	$ 89.98	$ 50.94	$ 89.98
GIS Data Enhancements	$ 10.40	$ 10.40	$ 10.40	$ 10.40
ADMS Core functionality	$ 26.00	$ 26.00	$ 26.00	$ 26.00
Protection & Arc Flash App (ADMS)	$ 0.38	$ 0.60	$ 0.38	$ 0.60
Underlying IT infrastructure	$ 8.27	$ 8.27	$ 8.27	$ 8.27
Appropriate Cyber Services	$ 4.16	$ 4.16	$ 4.16	$ 4.16
Network Management	$ 13.77	$ 13.77	$ 13.77	$ 13.77
OpTel Strategy	$ 46.25	$ 46.25	$ 46.25	$ 46.25
Existing VVO/CVR Platform	$ 4.45	$ 7.23	$ 4.45	$ 7.23
VVO/CVR App (ADMS)	$ 0.44	$ 0.71	$ 0.44	$ 0.71
FLISR App (ADMS)	$ 0.31	$ 0.54	$ 0.31	$ 0.54
DERMS	$ 9.49	$ 9.49	$ 9.49	$ 9.49
ITR Pilot Projects	$ 4.98	$ 4.98	$ 4.98	$ 4.98
Total	**$ 485.69**	**$ 583.35**	**$ 262.02**	**$ 359.67**

* A reduction in Feeder Monitoring Sensor costs in the Full Grid Mod Case is included as an avoided cost benefit for AMF rather than a reduction in cost between cases.

The horizon of the GMP spans more than 10 years and the maturity of the cost estimates presented and utilized in the BCA are of varying levels of refinement. Some of the projects in the GMP are still in the requirements definition phase of development at this time (e.g., DERMS), so these GMP cost estimates are still in the initial stage of estimation. Cost estimates will be refined over time, and the closer an investment gets to implementation, the more detailed and precise the estimate will become.

Also, note that while the cost estimates used in the BCA include all the costs necessary to deploy and maintain the grid modernization investments, costs associated with complementary and supporting elements outside of the GMP were excluded from this analysis due to the following considerations:

- The cost of any potential future policies, regulations, and requirements that may be necessary to optimize DER output or shift load are assumed to be either insignificant or cost-neutral, meaning that these costs would be incurred in either the Reference Case or the Grid Modernization cases.

- The cost and feasibility of the future load management programs that may be necessary to enable enhanced (i.e., 10%) load shift are too uncertain to estimate at this time. Therefore, the benefits associated with enhanced load shift capability are not included in the base case BCA results and are only included in a sensitivity analysis to highlight the additional benefit possible from more advanced load management programs in the future (e.g., advanced TVR design, NWA procurement, direct load control programs). See Section 8.5: Sensitivity Analysis for details.

8.4.3. Benefit Estimation

Many of the GMP functionalities and benefit impacts identified in *Section 5.5: Functionality and Benefit Impact Assessment* have been quantified using the Docket No. 4600 BCA methodology and inputs based on the detailed modeling described in *Section 4.3.2: Future State Assessment* and Attachment B, the Appendix. Where Docket No. 4600 did not provide full guidance, the Company used well-established BCA methodologies from other Company BCA efforts, including the Energy Efficiency and DR Program's RI Cost Test. The source for many of the avoided cost value components is the "*Avoided Energy Supply Components in New England: 2018 Report*" (AESC 2018 Study) prepared by Synapse Energy Economics for AESC 2018 Study Group, October 24, 2018. This report was sponsored by the electric and gas energy efficiency program administrators of National Grid in New England and is designed to be used for cost-effectiveness screening in 2019 through 2021.

The GMP benefit descriptions are presented in Table 8.7. In many cases, the quantifiable benefit is an avoided cost that is calculated based on the difference (or "delta") between a Reference Case and the Grid Modernization cases. Note that the BCA does not include benefits (or costs) associated with the future DER deployments compared to today (e.g., future GHG emissions reduction), only benefits compared to the Reference Case, which is assumed to have the same DER adoption (i.e., installed nameplate) as the Grid Modernization cases.[73] Benefits that were qualitatively addressed are presented in *Section 8.6: Qualitative Assessment*.

[73] These benefits (and costs) compared to today would be accounted for by the individual DER programs or policies that are developed to achieve the deployment levels assumed.

Table 8.7: Quantifiable GMP and AMF Benefit Category Descriptions

GMP and AMF Benefit Category	Quantitative Benefit Description	
	Grid Mod Only Case	Incremental AMF
Avoided O&M Costs	OPEX Labor Efficiency due to the ability for the system operator to perform remote switching and reduce communications, step checks, and field crew labor costs that would otherwise be required in a manual switching exercise; and due to GIS automation decreasing time spent creating and maintaining the various network models used for distribution system planning and operational models	OPEX Labor Efficiency due to eliminating meter reading (vehicles and personnel), enhanced outage management capabilities during storms, as well as reducing meter investigations, connect/disconnect service visits, and service-related damage claims
	Avoided Legacy OPEX Investments in RTB telecoms costs from existing Advanced Field Devices and future DERs, due to the proposed investments in OpTel Strategy	Avoided Legacy OPEX Investments in AMR annual software maintenance fees due to the proposed AMF investment
Avoided Capital Costs	Avoided Legacy CAPEX Investments in recurring standalone OMS license, VVO/CVR license (for existing deployments), and telecommunication investments necessary to convert DS0 to T1 circuit technology due to the proposed investments in ADMS, ADMS-based VVO/CVR App, and OpTel Strategy	Avoided Legacy CAPEX Investments in residential (AMR) and C&I (MV-90) meter hardware replacement and installation costs due to the proposed AMF investments, and avoided feeder sensor costs due to enhanced feeder monitoring enabled by AMF
	Avoided D-System Infrastructure Cost from ratepayers and DER developers due to the ability of the system operator to autonomously or remotely control power flows on the distribution system rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption	
Customer Benefits	Reduced Customer Energy Use and System Capacity Requirements as a result of operating distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption and peak demand from customer appliances (i.e., VVO/CVR)	Reduced Customer Energy Use due to an incremental improvement (additional 1% energy reduction) from VVO/CVR using AMF granular voltage data
		Reduced Customer Energy Use and System Capacity Requirements as a result of customer action based on more granular and timely energy usage data, integrating AMF with in-home energy saving technologies, and responding to advanced pricing to reduce demand for energy during peak demand periods (Reduced System

GMP and AMF Benefit Category	Quantitative Benefit Description	
	Grid Mod Only Case	**Incremental AMF**
		Capacity Requirements only), including reductions in EV charging during peak periods
	Reduced Outage Restoration Time due to the ability of the system operator and control system to quickly generate switch orders (i.e., ADMS-based SOM) and locate and isolate a fault and restore power (i.e., Reclosers, FLISR) rather than waiting for field crews to locate a fault and restore power	Reduced Outage Notification Time due to autonomous outage notifications alerting the Company to trouble before receiving customer outage calls. Integrating this functionality with the Company's Outage Management System (OMS) will reduce time from initial outage to Company notification, resulting in a decrease of total customer outage time, from occurrence of the initial outage to resolution.
	Reduced DG Curtailment due to the ability of the system operator to manage DERs and optimize power output from renewable DG rather than relying on seasonal curtailment to avoid thermal or voltage constraints	Note: additional Reduced DG Curtailment due to advanced pricing is addressed as a sensitivity analysis case (i.e., Enhanced Load Shift sensitivity case)
Societal Benefits*	Benefits due to a reduction in non-embedded central power plant emissions of CO_2, SO_2, and NO_x resulting from Reduced Customer Energy Use and Reduced DG Curtailment	Benefits due to a reduction in non-embedded central power plant emissions of CO_2, SO_2, and NO_x resulting from Reduced Customer Energy Use (i.e., energy insights/high bill alerts, TVR, and reductions in peak charging for EV customers)
		Note: additional emissions reductions due to further Reduced DG Curtailment using advanced pricing are addressed as a sensitivity analysis case (i.e., Enhanced Load Shift sensitivity case)
		Benefits due to a reduction in transportation-related emissions resulting from an improvement in Operational Efficiency (i.e., reduced "truck rolls" for meter reading, meter investigations, and connect/disconnect service visits)
	Note: economic development improvements due to net GMP investments are addressed as a sensitivity analysis case (i.e., Economic Development sensitivity case)	

* Note that while most emissions reductions benefits are included in Societal Benefits, some CO_2 reduction benefit is included as Customer Benefits due to "embedded" CO_2 costs associated with requirements of the Regional Greenhouse Gas Initiative (RGGI).

The GMP benefit category alignment with Docket No. 4600 benefits is presented in Table 8.8. Seventeen Docket No. 4600 benefits were quantified in the BCA. Additional Docket No. 4600 benefits are qualitatively addressed in *Section 8.6: Qualitative Assessment*.

Table 8.8: Quantifiable GMP and AMF Benefit Category Mapping to Docket No. 4600 Benefits

GMP Benefit Category	Docket No. 4600 Benefit
Avoided O&M Costs	Distribution Delivery Costs (Power System Level)
	Distribution System Safety Loss/Gain (Power System Level)
Avoided Capital Costs	Distribution Capacity Costs (Power System Level)
Customer Benefits	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Power System Level)
	Retail Supplier Risk Premium (Power System Level)
	REC Value (Power System Level)
	GHG Compliance Costs (Power System Level)
	Criteria Air Pollutant and Other Environmental Compliance Costs (Power System Level)
	Energy Demand Reduction Induced Price Effect (DRIPE)[74] (Power System Level)
	Electric Transmission Capacity Value (Power System Level)
	Forward Commitment Capacity Value (Power System Level)
	Distribution System and Customer Reliability/Resilience Impacts (Power System Level)
	Distribution System Performance (Power System Level)
Societal Benefits	GHG Externality Cost (Societal Level)
	Criteria Air Pollutant and Other Environmental Externality Costs (Societal Level)
	Public Health (Societal Level)
	Non-energy benefits: Economic Development (Societal Level)*

* Economic development improvements due to net GMP investments are addressed as a sensitivity analysis case (i.e., Economic Development sensitivity case)

Benefit estimates for the Full Grid Mod and Grid Mod Only cases are summarized in Figures 8.5 and 8.6. In all cases, the largest single benefit category is Customer Benefits. Also, the Avoided O&M Costs, Avoided Capital Costs, and Customer Benefits categories exceed grid modernization costs even before Societal Benefits are included. Benefits increase from the Low DER to the High DER scenario in both cases due primarily to significantly higher customer benefits in the High DER Scenario due to the larger number of customers benefiting from grid modernization.

[74] Demand Reduction-Induced Price Effect (DRIPE) is a measurement of the value of demand reductions in terms of the decrease in wholesale energy prices, resulting in lower total expenditures on electricity or other energy costs across a given system.

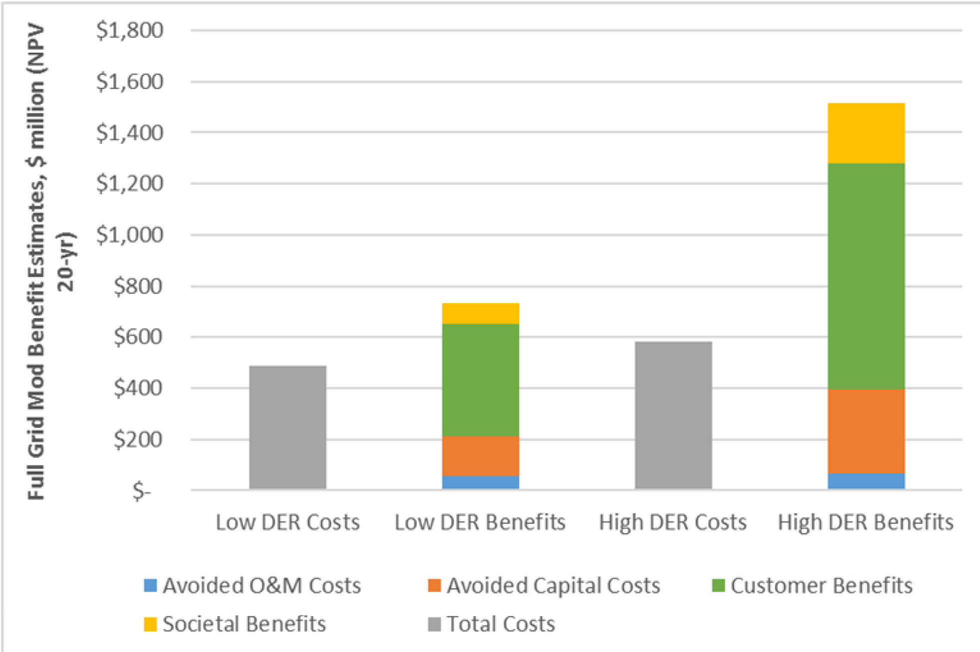

Figure 8.5: Benefit Estimates for Full Grid Mod Case

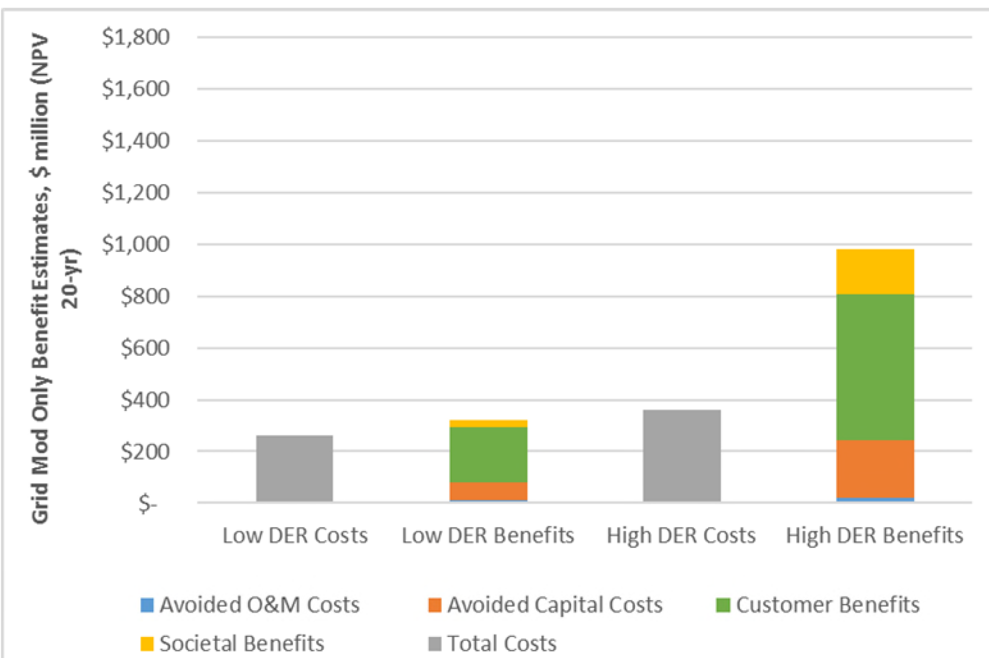

Figure 8.6: Benefit Estimates for Grid Mod Only Case

Benefit estimates for each specific quantified benefit in the Grid Mod Only Case are presented in Table 8.9. The top five benefit drivers for each scenario represent between about 60-70% of the total Grid Mod Only benefits. These top five benefits are summarized below.

Low DER Scenario:

- FLISR value of reliability improvement due to Reduced Outage Restoration Times
- Energy spot market price savings due to Reduced Customer Energy Use from VVO/CVR
- Developer avoided infrastructure savings due to Avoided D-System Infrastructure Cost from Load Optimization
- Non-embedded CO_2 benefit due to Reduced Customer Energy Use from VVO/CVR
- Reclosers value of reliability improvement due to Reduced Outage Restoration Times

High DER Scenario:

- Energy spot market price savings due to Reduced DG Curtailment from ADMS/DERMS
- FLISR value of reliability improvement due to Reduced Outage Restoration Times
- Non-embedded CO_2 benefit due to Reduced DG Curtailment from ADMS/DERMS
- Developer avoided infrastructure savings due to Avoided D-System Infrastructure Costs from Load Optimization
- Energy spot market price savings due to Reduced Customer Energy Use from VVO/CVR

Incremental AMF-related benefits are presented in the Implementation Plan document and detailed further in the Updated AMF Business Case filing.

Table 8.9: Detailed Benefit Estimates for Grid Mod Only Case

Grid Mod Only Case Benefit and Impact Category Estimates, $ million (20-year NPV)			Low DER	High DER
Avoided O&M Costs	OPEX Labor Efficiency	GIS network model savings	$ 8.24	$ 8.24
		Maintenance response savings (NRAs)	$ 0.82	$ 0.82
	Avoided Legacy OPEX Investments	Field device RTB telecoms savings (existing)	$ 1.10	$ 1.10
		DER RTB telecoms savings	$ 0.42	$ 9.53
Avoided Capital Costs	Avoided Legacy CAPEX Investments	Standalone OMS license savings	$ 0.72	$ 0.72
		Standalone VVO/CVR license savings (existing)	$ 1.98	$ 1.98
		DS0 to T1 telecoms savings	$ 3.55	$ 3.55
	Avoided D-System Infrastructure Cost (Load Optimization)	Ratepayer infrastructure savings (Small DG)	$ 13.58	$ 47.47
		Ratepayer RTB savings (Large DG)	$ 20.69	$ 72.85
		Developer infrastructure savings (Large DG)	$ 28.73	$ 98.96
Customer Benefits	Reduced Customer Energy Use (VVO/CVR)	Energy spot market price savings (excluding RGGI cost)	$ 51.09	$ 86.14
		Embedded CO_2 benefit (RGGI cost)	$ 5.82	$ 9.84
		DRIPE energy benefit	$ 1.64	$ 2.78
		Cross-DRIPE benefit	$ 0.68	$ 1.16
	Reduced System Capacity Requirements (VVO/CVR)	Transmission capacity savings	$ 21.80	$ 36.73
		Generation capacity savings	$ 14.25	$ 23.96
		DRIPE capacity benefit	$ 2.12	$ 3.60
	Reduced Outage Restoration Time	FLISR value of reliability improvement	$ 86.93	$ 128.09
		Reclosers value of reliability improvement	$ 24.54	$ 43.70
		SOM value of reliability improvement	$ 2.40	$ 1.55
	Reduced DG Curtailment (ADMS/DERMS)	Energy spot market price savings (excludes RGGI cost)	$ -	$ 195.53
		Embedded CO_2 benefit (RGGI cost)	$ -	$ 23.26
		DRIPE energy benefit	$ -	$ 5.60
		Cross-DRIPE benefit	$ -	$ 2.34
Societal Benefits	Reduced Customer Energy Use (VVO/CVR)	Non-embedded CO_2 benefit	$ 26.20	$ 44.12
		Public health benefit (SO_2)	$ 4.45	$ 7.50
		Criteria air pollutant benefit (NO_x)	$ 1.00	$ 1.69
	Reduced DG Curtailment (ADMS/DERMS)	Non-embedded CO_2 benefit	$ -	$ 102.69
		Public health benefit (SO_2)	$ -	$ 13.30
		Criteria air pollutant benefit (NO_x)	$ -	$ 3.82
Total			**$ 322.76**	**$ 982.62**

The following additional observations can be made for the Grid Mod Only case based on the benefit analysis and results:

- Avoided O&M Costs due to OPEX Labor Efficiency and Avoided Legacy OPEX Investments are relatively low compared to the much larger Avoided Capital Costs, Customer Benefits, and Societal Benefits.
- There are no Reduced DG Curtailment benefits in the Low DER scenario because there were no periods of negative load (i.e., reverse power flow) based on the Company's state-level assessment using the Low DER forecast. However, there could be specific locations where DG curtailment would be necessary, even in the Low DER Scenario, but this level of detailed analysis was not undertaken for the GMP.

Note that quantified benefits associated with Enhanced Load Shift and Economic Development and are not included in the base case benefit estimates in this section. Instead, they are included in *Section 8.5: Sensitivity Analysis*.

8.5. <u>Sensitivity Analysis</u>

As described in *Section 3: Risk Management Approach*, developing a 10-year plan in a fast-changing environment requires acknowledgement that there are a number of uncertainties. These uncertainties create risks with respect to the scope and timing of investments within the GMP and the benefits to be achieved. The Company has taken several steps to better understand uncertainties and manage the associated risks, most notably creating this 10-year roadmap to guide the development of projects and programs, the development of two future state scenarios that "bookend" the range of likely customer DER adoption, and other risk mitigating steps outlined in Section 3.

In addition to providing information in terms of how the quantified benefits and costs compare for the range of future scenarios, the GMP BCA also provides the Company and external stakeholders with a better understanding of the key factors that impact the quantified benefits and costs and allows both parties to focus future efforts on better understanding and influencing those factors in a positive way. The following sensitivity analysis evaluates the BCA impact of some of the key factors quantitatively.

8.5.1. <u>Alternative BCA Formulations</u>

During internal and external (e.g., GMP and AMF Subcommittee) review meetings, stakeholders identified a number of alternatives to the base case BCA formulation (base case). This section presents BCA results based on the following alterations to the Company's base case BCA to show how these alternative BCA formulations affect the GMP cost-effectiveness. The first four alternatives use less conservative assumptions than the base case, while the last two alternatives use more conservative assumptions than the base case.

1. Include economic development impacts of GMP investments
2. Include Rest of Pool (ROP) DRIPE effects
3. Use lower societal discount rate (i.e., Inflation = 3%) instead of the Company's after-tax weighted average cost of capital (WACC = 6.97%)
4. Include enhanced load shift impact (i.e., 10% load shift)
5. Exclude renewable DG curtailment benefit
6. Exclude SAIFI value of reliability improvement benefit due to FLISR

Economic Development Included

The Docket No. 4600 Framework[75] includes consideration of societal economic development benefits and notes that such benefits can be reflected via a qualitative assessment or, alternatively, can be quantified through detailed economic modeling. The Company and GMP and AMF Subcommittee members agree that economic development benefits are important. However, including these benefits in the base case BCA results can be problematic due to the relatively high uncertainty associated with these benefits related to GMP investments, which can discredit other components of the BCA. Additionally, because the benefits can be large, they create a "masking" effect. For these reasons, the GMP did not consider economic development benefits in its base case results but included it here as a sensitivity. A more detailed discussion of economic development benefits can be found in Attachment B, the Appendix and the Updated AMF Business Case filing (Section 7.6.1 and Appendix 10.5.2).

Economic impacts were quantified using the Regional Economic Models, Inc. (REMI) model of the Rhode Island economy, which estimates the increased economic activity resulting from GMP investments. The overall societal impact is measured using the net Rhode Island gross domestic product (GDP), which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms. The Economic Development Impact assessment for the Full Grid Mod Case investments resulted in \$267 million and \$553 million increases in net GDP growth in Rhode Island for the Low DER and High DER scenarios, respectively. Grid Mod Only investments resulted in \$151 million and \$437 million increases for the Low DER and High DER scenarios, respectively. Details are provided in Attachment B, the Appendix. Including these Economic Development impacts will increase the GMP benefits, which will increase the benefit-cost ratio.

ROP DRIPE Included

Demand Reduction Induced Price Effect (DRIPE) is the reduction in prices in energy and capacity markets resulting from the reduction in need for energy and/or capacity due to reduced

[75] *See* Raab Associates, Ltd., *Docket 4600: Stakeholder Working Group Process, Report to the Rhode Island Public Utilities Commission* at 16 (April 5, 2017); *see also* Docket 4600 Guidance Document, *supra* note 9 (stating, "[w]here quantification is not possible or not practical, the proponent should so explain. Regardless of whether the quantification can be fully completed, a qualitative analysis should be included.").

demand from electric system investments. AESC provides values for two types of DRIPE benefits: Intrastate and Rest of Pool (ROP). Intrastate DRIPE benefit takes credit for the reduced clearing price for Rhode Island customers, while ROP DRIPE benefit takes credit for reduced clearing price for customers across New England. The base case BCA results exclude ROP DRIPE based on the interpretation of the RI Test used for this filing, which focuses on benefits accrued to Rhode Island customers. While the base case BCA includes only Intrastate DRIPE, stakeholders expressed an interest in seeing results that include the ROP portion of DRIPE as well. Including ROP DRIPE will increase the GMP benefits, which will increase the benefit-cost ratio.

Societal Discount Rate

The Company maintains that the most reasonable rate to discount future year costs and benefits for GMP investments is the Company's after-tax WACC (currently 6.97% nominal) due to the fact that the GMP investments are utility investments, and after-tax WACC is the Company's effective discount rate. However, stakeholders requested to see results given a lower societal discount rate. Using a lower nominal discount rate of 3%, which is consistent with the Company's 2020 Energy Efficiency Plan discount rate,[76] values cash flows in later years more than a higher discount rate. Since most costs occur in early years, but benefits occur in later years, the net effect is an increase in the benefit-cost ratio.

Enhanced Load Shift Included

The GMP investments can facilitate load shifting from high demand periods to negative load periods (i.e., periods of excessive renewable DG generation) by enabling flexible demand. Examples of longer-term flexible demand include EV charging, stationary energy storage, and perhaps in the future, electric vehicle-to-grid charging/discharging. These demand loads are particularly flexible when customer DR programs and AMF with TVR are used to target both peak load reduction and "negative load filling." For example, load shift capability provided by AMF with TVR could enable customers to respond to price signals by reducing energy use during on-peak demand periods and increasing energy use during negative load periods. This shifting of energy consumption between time periods can reduce customer energy costs and maximize renewable generation utilization.[77] This load shift would likely be accomplished

[76] The Company's 2020 Energy Efficiency Plan uses a discount rate that appropriately reflects the risks of the investment of customer funds in energy efficiency; in other words, a discount rate that indicates that energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk. The 2020 Energy Efficiency Plan uses a nominal discount rate of 2.91% (real discount rate of 0.84%).

[77] The currently envisioned, near-term TVR structure described in the Updated AMF Business Case would only shift load from the current on-peak periods (i.e., 11 am – 9 pm in the Summer months) to off-peak periods (i.e., 9 pm – 11 am in the Summer months). However, in a future, with higher renewable DG adoption, on-peak and off-peak periods would change significantly, such that TVR could be structured to shift load away from a later on-peak period. (e.g., 5 p.m. – 9 p.m.) and to negative load periods when renewable power is most abundant (e.g., 7 a.m. – 3 p.m. for solar PV).

through customer response using the most cost-effective flexible demand approach available to each customer, whether the energy provider uses TVR or some other means of incentive or compensation (e.g., NWA procurement, direct load control program).

However, the cost and feasibility of the future load management programs that may be necessary to enable enhanced load shift are too uncertain to estimate at this time. Therefore, the benefits associated with enhanced load shift capability are not included in the base case, but they are only included in this alternative formulation to highlight the additional benefit possible from more advanced load management programs in the future (e.g., advanced TVR design, NWA procurement, direct load control program).

For this alternative formulation, the Company has envisioned a Load Shift capability equal to 10% of demand (i.e., on-peak period demand to negative load period demand) could be used by system operators to keep system parameters within predetermined limits without requiring DG curtailment.[78] This alternative BCA formulation also assumes the 10% load shift can be realized by a future load management program without significant costs, or that the costs would be offset by other benefits.[79]

Under the High DER scenario, an enhanced load shift of 10% was estimated to reduce annual renewable DG curtailment from 3% down to just 1% by 2030 by enabling customers to respond to price signals to increase demand for energy during negative load (i.e., excess renewable power generation) periods. Enhanced load shift was also estimated to reduce system capacity requirements by enabling customers to respond to price signals to reduce demand for energy during peak demand periods. These reductions in DG curtailment and system capacity requirements will increase the GMP benefits in the High DER Scenario, which will improve the benefit-cost ratio.

FLISR SAIFI Benefit Excluded

The targeted deployment of Advanced Reclosers & Breakers, which is part of the Company's GMP, can reduce both the duration and frequency of all outages including momentary outages (i.e., outages lasting less than 1 min). The addition of FLISR to the deployment of Advanced Reclosers & Breakers will reduce outage duration and frequency, but only the frequency of sustained outages (i.e., outages greater than 1 minute). Without FLISR, outage durations might be an hour or more for some customers while crews are dispatched to locate and isolate the fault

[78] National Grid's Worcester Smart Energy Pilot evaluated the energy and demand savings from current TVR structures and found load 4.7% (29 kWh per month) weighted average energy savings across the technology groups for active "critical peak pricing" (CPP) customers over the four years of the pilot. *See* Navigant, *National Grid Smart Energy Solutions Pilot, Final Evaluation Report* (May 5, 2017). Therefore, the Company deemed 10% to be a high, but not overly aggressive, future load shift estimate assuming an appropriate TVR structure.
[79] Note that if the costs exceeded the benefits (i.e., BCA <1), it is assumed the programs would not be progressed in their relevant filings.

and restore power to customers downstream of the fault. With FLISR, these steps can be performed in a matter of seconds, so outages can be converted from sustained to momentary outages. Typical reliability metrics include outage duration, which is reported based on the System Average Interruption Duration Index (SAIDI) and outage frequency, which is reported based on the System Average Interruption Frequency Index (SAIFI). In Rhode Island, SAIFI is reported based on the frequency of sustained outages lasting greater than 1 minute. So, reducing customer outages to less than 1 minute will reduce the reported SAIFI.

The GMP's "FLISR value of reliability improvement" benefit is estimated based on the monetization of customer impacts as presented in the DOE's Interruption Cost Estimate (ICE) Calculator, which uses SAIDI and SAIFI improvements as inputs to the Calculator.[80] The Company believes it is appropriate to quantify the FLISR benefit using both the estimated SAIDI and SAIFI improvements as inputs to the DOE ICE Calculator. However, some internal stakeholders expressed concern over the uncertainty of the actual customer value of converting a sustained outage to a momentary outage. Therefore, this sensitivity case was developed to show the impact to the BCA if SAIFI reductions were excluded for the FLISR benefit. Excluding the FLISR SAIFI benefit will decrease the GMP benefits, which will reduce the benefit-cost ratio.

DG Curtailment Benefit Excluded

The High DER scenario modeled as part of the Company's state-level analysis resulted in a net load curve with several negative load periods due to the prevalence of renewable DG, particularly solar DG (see *Section 5.4.2: State-Level Analysis*). This means that renewable DG would be in excess of load - or in other words, at times there would be more renewable generation available than Rhode Island customers needed at that time. When too much electricity is fed into the grid from renewable DG in relation to customer demand, resulting in negative load, high voltages and thermal congestion will result.

Without grid modernization investments, grid issues due to negative loads cannot be monitored or managed in a granular manner, so the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the design limitations of the system, which in this case is the estimated seasonal minimum load for the State (i.e., seasonal curtailment). This seasonal curtailment results in an average renewable DG curtailment of 20% of its annual energy output under the High DER Scenario by 2030.

Alternatives to DG curtailment are limited. Possible alternatives and their shortcomings are addressed in *Section 5.4.2: State-Level Analysis*. Despite these shortcomings, this alternative BCA formulation envisions a situation where there is an alternative approach to seasonal DG curtailment (without grid modernization), and that its CAPEX, OPEX, and RTB costs are zero.

[80] The DOE ICE Calculator is a tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements. Details are provided at https://www.icecalculator.com/home

Excluding the DG Curtailment benefit will decrease the GMP benefits for the High DER Scenario, which will reduce the benefit-cost ratio.

Results

A summary of BCR results for the alternative BCA formulations relative to the Full Grid Mod Base Case is shown in Figure 8.7. Table 8.10 provides the specific cost and benefit increases and decreases estimated relative to the Full Grid Mod Base Case. The Company notes that, while some of the alternative formulations could be combined in an "ala carte" manner to surmise combined effects (e.g., Economic Development, ROP DRIPE), the effects of the Societal Discount Rate, Enhanced Load Shift, and DG Curtailment formulations are more complex and cannot be combined with other alternative formulations without additional analysis.

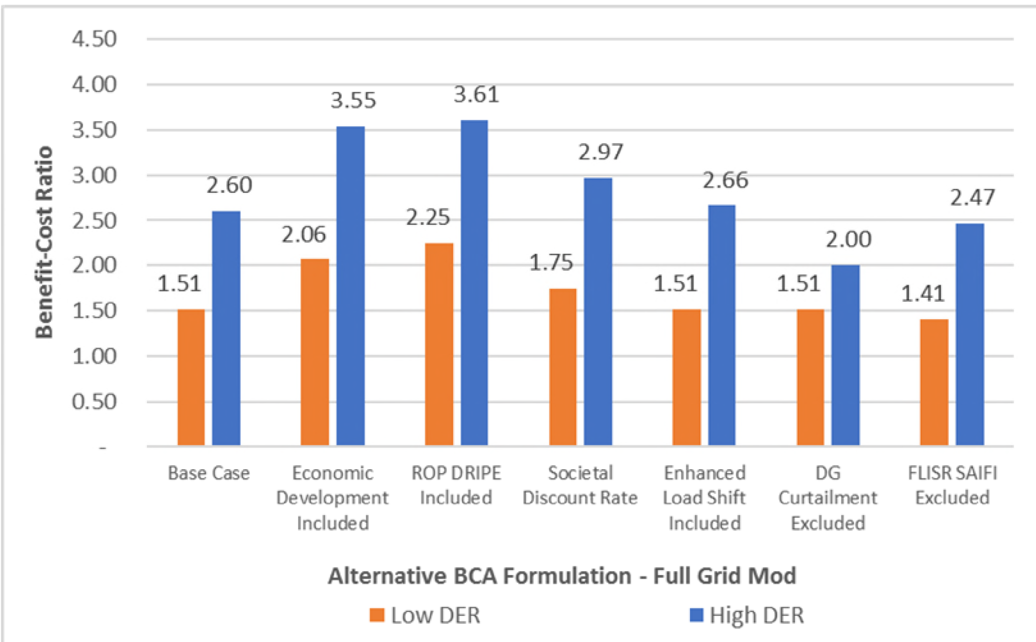

Figure 8.7: Impact of Alternative BCA Formulations on BCRs – Full Grid Mod Case (20-Year NPV)

Table 8.10: Impact of Alternative BCA Formulations on BCA Results – Full Grid Mod Case (20-Year NPV)

Alternative BCA Formulation – Full Grid Mod Case, 20-Yr NPV	Low DER			High DER		
	Effect on Costs ($M)	Effect on Benefits ($M)	Benefit Cost Ratio	Effect on Costs ($M)	Effect on Benefits ($M)	Benefit Cost Ratio
Base Case	$486	$736	1.51	$583	$1,515	2.60
Economic Development Included	$0	$267	2.06	$0	$553	3.55
ROP DRIPE Included	$0	$357	2.25	$0	$589	3.61
Societal Discount Rate	$166	$402	1.75	$219	$866	2.97
Enhanced Load Shift Included	$0	$0	1.51	$0	$38	2.66
DG Curtailment Excluded	$0	$0	1.51	$0	-$347	2.00
FLISR SAIFI Excluded	$0	-$51	1.41	$0	-$76	2.47

The quantitative benefits attributed to the GMP with AMF (i.e., Full Grid Mod Case) outweigh the costs in all alternative scenarios. Including economic development impacts, ROP DRIPE effects, and a lower societal discount rate all resulted in additional quantified benefits, which increased the BCRs by between about 15-50% compared to the base case. Including enhanced load shift capabilities increased the BCR of the High DER Scenario by 3%. Also, while excluding the FLISR SAIFI and renewable DG curtailment benefits had negative impacts on the quantified benefits, the BCRs for both the Low DER and High DER scenarios were still much greater than one, even for the Low DER Scenario.

The summary of BCR results for the alternative BCA formulations relative to the Grid Mod Only base case is shown in Figure 8.8. Table 8.11 provides the specific cost and benefit increases and decreases estimated relative to the Grid Mod Only base case.

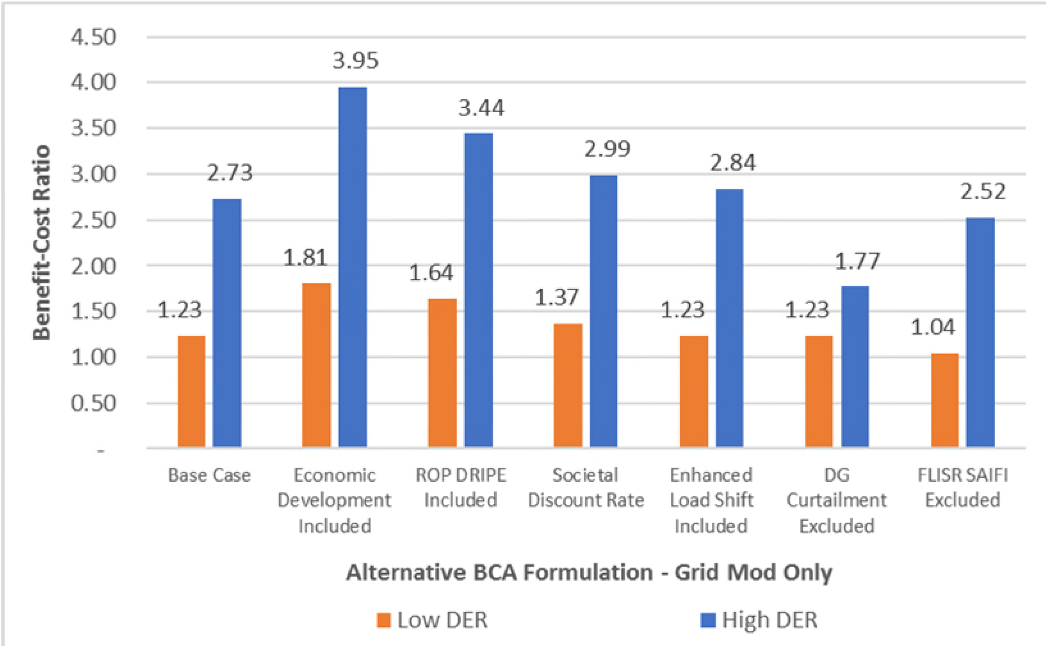

Figure 8.8: Impact of Alternative BCA Formulations on BCRs – Grid Mod Only Case (20-Year NPV)

Table 8.11: Impact of Alternative BCA Formulations on BCA Results – Grid Mod Only Case (20-Year NPV)

Alternative BCA Formulation – Grid Mod Only Case, 20-Yr NPV	Low DER			High DER		
	Effect on Costs ($M)	Effect on Benefits ($M)	Benefit Cost Ratio	Effect on Costs ($M)	Effect on Benefits ($M)	Benefit Cost Ratio
Base Case	$262	$323	1.23	$360	$983	2.73
Economic Development Included	$0	$151	1.81	$0	$437	3.95
ROP DRIPE Included	$0	$106	1.64	$0	$255	3.44
Societal Discount Rate	$110	$187	1.37	$162	$575	2.99
Enhanced Load Shift Included	$0	$0	1.23	$0	$38	2.84
DG Curtailment Excluded	$0	$0	1.23	$0	-$347	1.77
FLISR SAIFI Excluded	$0	-$51	1.04	$0	-$76	2.52

The quantitative benefits attributed to the GMP without AMF (i.e., Grid Mod Only case) outweigh the costs in all alternative scenarios. Including economic development impacts, ROP DRIPE effects, and a lower societal discount rate all resulted in additional quantified benefits, which increased the BCRs by between about 10-50% compared to the base case. Including the enhanced load shift capability increased the BCR by 4% for the High DER Scenario. Also, while excluding the FLISR SAIFI and renewable DG curtailment benefits had negative impacts on the quantified benefits, the BCRs for both the Low DER and High DER scenarios were still greater than one, even for the Low DER Scenario.

8.5.2. Key Input Assumptions Sensitivity

In order to assess the impact of important variables on the BCA results, a range of values was developed for a set of key input assumptions for the Grid Mod Only Case. This sensitivity analysis uses a range of more conservative and less conservative assumptions than the base case, as summarized below. A separate sensitivity analysis for the incremental AMF investments is presented in the Updated AMF Business Case.

- Avoided Cost of Carbon benefit assumption range from 50% to 150% of the base case input assumption. Note that this sensitivity also addresses the added uncertainty of future electric sector emissions rates.
    - Base case = $100/ton CO_2 equivalent based on "global" marginal abatement cost estimates assuming carbon capture and sequestration is the least cost abatement technology[81]
    - Low end of the range was selected to capture future "local" marginal abatement cost estimates assuming offshore wind is the least cost abatement technology in New England (e.g., $68/ton CO_2 equivalent)[82]
    - High end of the range was selected to capture damage cost estimates including incorporation of extreme risk (e.g., >$125/ton CO_2 equivalent)[83]

- Avoided D-System Infrastructure Investment benefit range from 70% to 130% of the base case avoided cost estimate
    - Base case = $63 million and $219 million (20-year NPV) based on Future State Modeling results for Low and High DER scenarios, respectively
    - Range of +30% and -30% was selected based on observations in average DG interconnection costs over the past three years

[81] Synapse Energy Economics, *Avoided Energy Supply Components in New England: 2018 Report*, 143 (Orig. released March 30, 2018, amended October 24, 2018) (Prepared for AESC 2018 Study Group; based on a Natural Gas Combined Cycle plant with geological storage.).
[82] *Id*. at 143. Based on the incremental cost of offshore wind estimated to be $30/MWh, and the annual average marginal emission rate of 0.46 short tons of CO_2/MWh based on the U.S. average "uncontrolled emissions factor" for natural gas generators. Note that most recent electric generator air emissions report from ISO-NE states that the marginal emissions factor for ISO-NE generators is 0.33 short tons of CO_2/MWh, which would result in a carbon cost of $90/ton CO_2 equivalent. ISO-New England, System Planning, *2018 ISO New England Electric Generator Air Emissions Report (*May 2020).
[83] J.X.J.M van der Bergh & W.J.W. Botzen, *A Lower Bound of the Social Cost of CO_2 Emissions,* 4 Nature Climate Change 253-258 (2014).

- VVO/CVR-based customer energy use and system capacity requirement reduction range from 2% to 4%
  - Base case = 2.86-2.93% based on early results from the Company's VVO/CVR Pilot using Utilidata's AdaptiVolt technology at five substations in Rhode Island
  - Range was selected to capture the variability of early measurement and verification (M&V) results from the Company's VVO/CVR Pilot. The high end of the range also captures the 4% energy savings the Company's VVO/CVR industry partner has demonstrated with other utilities.
- GMP portfolio investment cost assumptions range from 70% to 130% of the base case input assumption
  - Base case = $262 million and $360 million (20-year NPV) based on CAPEX, OPEX, and RTB cost estimates for each GMP solution for the Low and High DER scenarios, respectively
  - Range of +30% and -30% was selected for consistency with the Avoided D-System Infrastructure Investment sensitivity range

Results

Figures 8.9 and 8.10 show the range of benefit-cost ratios achieved by each key input assumption sensitivity for the Grid Mod Only Case under the Low and High DER scenarios. A separate sensitivity analysis for the incremental AMF investments is presented in the Updated AMF Business Case.

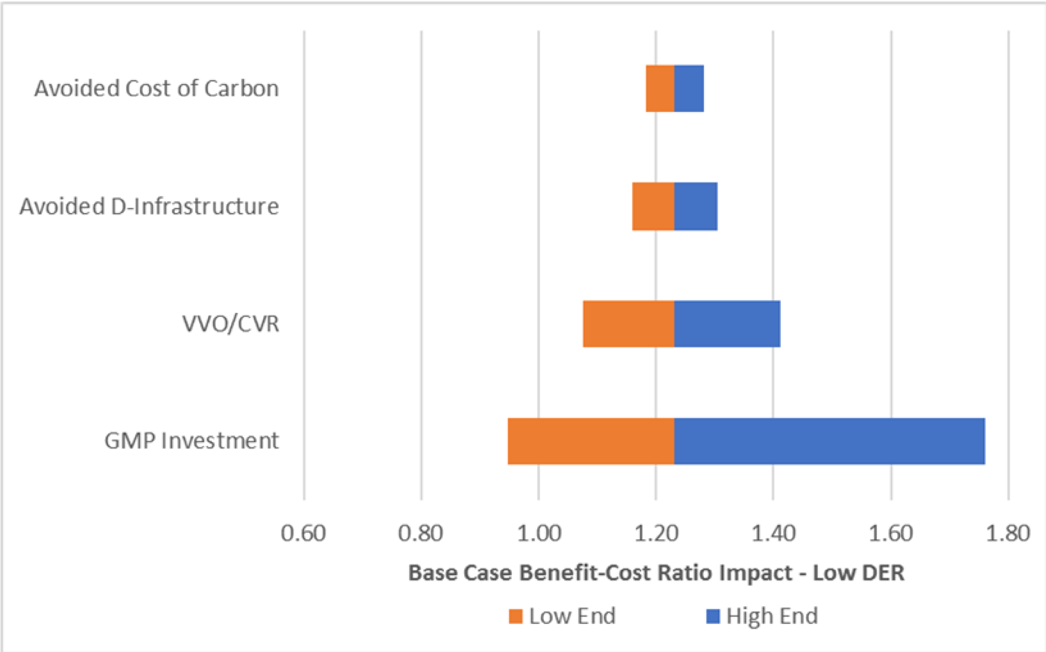

Figure 8.9: Impact of Key Input Assumption Sensitivity on the Base Case Benefit-Cost Ratio – Grid Mod Only Case Under the Low DER Scenario

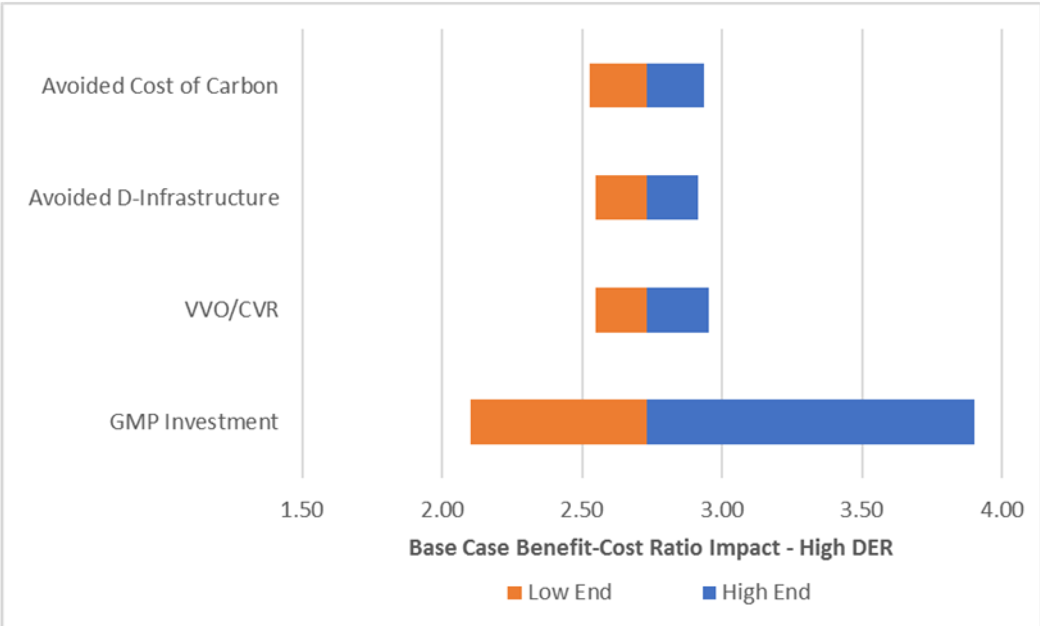

Figure 8.10: Impact of Key Input Assumption Sensitivity on the Base Case Benefit-Cost Ratio – Grid Mod Only Case Under the High DER Scenario

As can be seen, uncertainty in the GMP investment cost estimates creates the widest range of potential BCR results. Fortunately, a large fraction of the GMP investment cost estimate is based on the deployment of solutions that the Company has significant experience with, including Advanced Reclosers & Breakers, Advanced Capacitors & Regulators, and Feeder Monitoring Sensors. However, an exact cost estimation for all solutions in the GMP can be challenging given the long time-frame of the GMP analysis. To address this uncertainty, the Company envisions updating BCA results in concert with cost recovery requests for grid moderation investments in the appropriate regulatory forum.

Another key uncertainty is the VVO/CVR energy savings, particularly for the Low DER Scenario, which relies heavily on VVO/CVR energy savings for a large portion of the total benefits (both customer and societal benefits). Uncertainty in VVO/CVR energy savings is expected to be reduced over time as the Company continues VVO/CVR pilot projects and M&V in all of its jurisdictions. A summary of the Company's ongoing and planned pilot projects in all jurisdictions is presented in Attachment B, the Appendix.

The avoided D-system infrastructure cost and the avoided cost of carbon uncertainties have relatively smaller impacts, but these estimates will also be updated with the latest information in concert with cost recovery requests for grid modernization investments in the appropriate regulatory forum. Details are provided in Attachment B, the Appendix.

8.6. Qualitative Assessment

In addition to the quantified benefits presented in this BCA, per Docket No. 4600 Guidance, the Company is providing additional non-quantified benefits that should be recognized qualitatively. These benefits are not quantified at this time due to lack of data or lack of accepted method. However, these benefits represent important additional grid modernization value, as is explained in this section. If considered as part of the BCA, these benefits can be thought of as directionally increasing the BCR and potentially making the grid modernization programs even more valuable and cost-effective. These benefits will continue to be evaluated and could be quantified in future BCA results as additional data and methods are developed.

8.6.1. Avoided O&M Cost

OPEX Labor Efficiency due to OpTel Network Refresh: Much of the telecommunications equipment in the field and at substations are near the product line's end-of-life where technical support and replacement parts are more challenging to obtain. With age, the reliability of electronics deteriorates. Equipment failure during normal operation poses additional repair costs versus preventative maintenance and technology refresh. With advances in network technology and modern manufacturing, the new equipment is designed and built for greater longevity and higher mean time between failure (MTBF). The new equipment also has the capability of integrating multiple communications systems and physical connections and media, which eases transition and cost from legacy equipment as well as provides flexibility for network design and options. See also *Reduced Customer Outages due to OpTel Network Refresh* in Section 8.6.2, below.

Avoided Legacy OPEX Investments due to Flexible OpTel Network: The proposed OpTel Strategy will enable operational efficiencies and overall cost reduction due to combining disparate legacy telecommunications systems. Historically, across the utility industry, network communications have been point solutions driven by a specific requirement of the operating business. This approach has led to a variety of technologies and systems that were limited to a single use case. The proposed OpTel Strategy investment will develop a common network framework that is flexible and standards-based to allow and support many of the current and forthcoming use cases requiring network connectivity.

Improved Long-Term Forecasting for Planning due to Granular Data: Currently, feeder level data combined with generic load shape analysis is used to model remote end feeder performance. The granular data and improved situational awareness from AMF, Advanced Field Devices, and ADMS provides a step change in available data for grid planning and operations. This data can be used to more accurately design and plan for future distribution system needs through better forecasting of where and when DERs will be located, used, and how the distribution system will perform over time. AMF also provides more timely, granular values that can be aligned with other system data to create actual loading and voltage profiles at all points along a feeder. This complete data set can be modeled directly, and more detailed load and DER forecasts can be developed for planning needs.

Improved Operational Efficiency due to Granular Data: The granular and more frequent operational and performance data collected from AMF, Advanced Field Devices and ADMS, will help the Company determine the asset health of equipment and identify where maintenance should be performed and may help detect asset failures earlier, which would support condition based maintenance and mitigate possible equipment failure related outages. This can result in both lower O&M costs and more efficient utilization of field crews and crew time and shorten "trouble call" and outage response times. See also *Reduced Customer Outages due to Granular Data* in Section 8.6.2, below.

Improved Operational Efficiency and Worker Safety due to Mobile Dispatch: Today dispatchers from the Distribution Control Centers and Storm Rooms utilize OMS to view customer calls and predicted outage locations. They prioritize the "trouble calls" and outages and assign them to appropriate field crews based on capability and location as optimally as possible. ADMS-based Mobile Dispatch will interface with OMS and allow field crews with handheld devices to assign and dispatch themselves to outages based on their location, capabilities, and equipment. This can result in more efficient utilization of field crews and crew time and shorten "trouble calls" and outage response times. In addition, field crews will be able to update details concerning their time of arrival, incident details once on location, and estimated restoration times rather than calling that information into the centralized dispatch locations. In turn, the crews will receive near real-time updates directly on their devices to enable situational awareness in the field and reduce field-to-control center process steps increasing time spent on the task at hand. The proposed Mobile Dispatch pilot project included under the ADMS category of investment includes a limited deployment of mobile dispatch capabilities to select field personnel, with a view to explore options to improve the "trouble calls" response and outage restoration process. Learnings from the pilot will be applied towards developing the de-centralized process flows and requirements for a full deployment. See also *Improved Restoration Times due to Mobile Dispatch* in Section 8.6.2, below.

Improved Operational Efficiency due to Protection Coordination: Without GMP investments in ADMS, Advanced Field Devices, and an ADMS-based Protection & Arc Flash App, a labor-intensive process to make the system safe for workers would be required, especially under high DER adoption scenarios. In cases where DERs could create protection system coordination issues or negatively affect arc flash levels, field crews would need to be dispatched to reprogram protection devices, rearrange the system, or even disconnect DERs at certain times. In addition, ADMS will utilize real time data via DSCADA to inform the load flow allowing the protection coordination to be based on the actual state of the network rather than the "normal" study configuration.

8.6.2. <u>Customer Benefits</u>

Improved Customer Choice and Control due to Customer Information Sharing: AMF and other grid modernization investments will enable improvements in customer energy usage information sharing, third-party information sharing, and access to third-party service providers, which empowers customers to better understand and prioritize among solutions to best manage energy usage and costs. Specifically, these investments will improve retail competition, flexible demand, and integration of commodity and energy services. Additionally, these investments will improve third-party DER markets by enabling more cost-effective DER network access. When paired with Advanced Pricing, customers will have the opportunity to respond to price signals and achieve even greater savings. The AMF and other grid modernization capabilities that provide this benefit include:

- Customer Data Sharing through the CEMP will improve customer's access to third-party programs and offerings that are intended to drive innovation and provide additional value to customers, while encouraging new industry participants to enter the market with new customer offerings.

- Timely, Granular Customer Load Data (e.g., detailed billed energy use) from Enhanced Customer Insights & Alerts and Customer Data Sharing through the CEMP will enable the Company to clearly identify and communicate to customers when and where customer energy solutions provide the most value to customers and the grid. This will help optimize existing customer energy programs, facilitate new programs, and enhance EE, DR, and conservation offerings. Overall, timely, granular customer load data will enhance program value and enable customers to better prioritize among solutions to best manage energy usage and costs.[84]

- Granular Customer Load Data from AMF combined with Customer Data Sharing through the CEMP will enable customers to make informed decisions about participation in energy management efforts and heating and vehicle electrification.

- Customer Information Sharing and Distribution System Information Sharing through AMF investment in CEMP and the System Data Portal will improve customer choice and control and improve DER cost-effectiveness by clearly communicating to customers and third party DER markets where and when DERs provide the most value to the grid and are likely to have lower costs and other barriers to interconnect. This will help optimize existing DER investments, facilitate new ones, and enhance DER offerings, increasing the value of programs including DG, energy storage, EV, EHP, DR, and enabling customers to better prioritize among solutions. Details are provided in *Section 3: Rhode Island System Data Portal* of the Implementation Plan and the Updated AMF Business Case.

As AMF analytics continue to evolve, new use cases will be developed. For example, consider an AMF electric vehicle analytics offering that detects which customers are charging an EV at their home, determines the size of a customer's EV charger, and understands charging patterns, such as peak time charging. The Company could then tailor a targeted marketing program to enroll those customers into EV rates or use that information to plan infrastructure upgrades accordingly. The AMF grid-edge computing platform provides a technology platform that will improve and evolve over time. As more applications are developed and implemented, new customer solutions will be made available, expanding on the table of AMF Future Functionalities provided in Section 5 of the Updated AMF Business Case.

Improved DER Experience due to DER Integration: Grid modernization investments enable improved customer DER experience, such as better DER location selection, streamlined DER interconnection processes, flexible interconnection options, reductions in time to interconnect, and better customer and third party information sharing and services. By reducing costs and other barriers to interconnection, grid modernization will help more Rhode Island customers

[84] For example, as discussed in the Section 5 of the Updated AMF Business Case filing, load disaggregation will provide customers with the ability to view consumption information at the appliance level and make informed decisions accordingly. Consider a homeowner who observes that the central air conditioner is consuming considerably more electricity than the previous summer due to aging equipment. The customer may then proactively choose to upgrade that equipment to a high efficiency option, utilizing an Energy Efficiency program. As the technology matures, one can envision the ability to provide automated, personalized recommendations to customers.

invest in their own DER technologies in areas where these technologies are most cost-effective. The grid modernization capabilities that provide this benefit include:

- Distribution System Information Sharing through the System Data Portal will improve DER cost-effectiveness by clearly communicating to customers and third party DER markets where and when DERs provide the most value to the grid and are likely to have lower costs and other barriers to interconnect.

- Grid Optimization and DER Operational Control through ADMS and DERMS will allow for a higher level of DER operational integration and could be used to reduce interconnection costs and enable larger DER interconnections making DERs more cost effective to deploy in the state.

- Interval Energy and Voltage Data from AMF at the customer level will enable verification and settlement of DER services provided to or received from the grid.

- Two-way Communications from AMF will enable the exchange of information and/or control with in-home, business, or grid-connected DER technologies. In the future, this will provide new opportunities for automated responses to TVRs. For example, customers with energy storage or an EV charger may have automated controls in the future that can optimize when to operate, initiating charging when prices are low, and then, in the case of the storage system, discharging when prices are high.

See also *Economic and Environmental Benefits due to DER Integration* in Section 8.6.3, below.

More Equitable Cost Allocation due to Granular Data: Grid modernization will enable improvements in the ability to allocate costs to different classes of customers in a way that more precisely reflects their respective contributions to system-level costs, and will support development of more cost-reflective rates and pricing that limits cross-subsidization. Through the use of future pricing and allocation mechanisms like TVR, AMF and other grid modernization investments will enable the Company to more accurately reflect the costs of producing and delivering electricity, which will promote economic efficiency and lead to a lower-cost system. In addition, when the prices consumers pay are more closely aligned with the costs they represent, TVR promotes a more fair and equitable allocation of electricity sector costs.[85] AMF and other grid modernization investments are needed to provide granular (both in time and space) grid-level data.

More Equitable Benefit Allocation due to Granular Data: Grid modernization will enable improvements in the ability to allocate benefits to compensate customer- or third-party owned

[85] As explained in the Updated AMF Business Case filing, Attachment C, the Company is not making a rate design proposal at this time.

DERs in a way that is more reflective of actual system benefits (e.g., shift from current net energy metering programs to location- and market-based DER pricing). Benefits will be attributed more equitably due to grid modernization investment's ability to provide better customer facing program incentives (e.g., DR incentives) and NWA compensation based on the granular grid-level data. Today, customer load management programs like energy efficiency and DR are used to lower the cost of wholesale electricity and reduce the bulk system's peak demand, and NWA programs address generation, transmission, and distribution constraints through the use of DERs. In the future, under high DER penetration scenarios, load management programs including energy efficiency, DR, energy storage, and NWA programs can be used in combination with TVR and/or new DG tariffs to not only reduce bulk and distribution-level peak loads, but also shift customer loads to times when renewable DG output power exceeds the grid's demand for electricity.

Reduced Customer Energy Use due to Network Model Integration: Beyond FY26, when VVO/CVR is centralized and controlled by ADMS rather than the existing standalone VVO/CVR platform, the Company anticipates additional energy saving benefits beyond what has been assumed in the quantitative BCA, because the ADMS-based VVO/CVR platform will operate on the "as-switched" network model informed by underlying real time load flow. This also allows VVO/CVR to operate when the grid is in an abnormal configuration due to emergency or planned circuit reconfigurations resulting in additional incremental benefits in addition to the baseline VVO/CVR energy savings.[86] Additional analysis and experience with the ADMS-based VVO/CVR controller is necessary to accurately quantify this benefit.

Reduced Customer Energy Costs due to Enhanced Load Shift: AMF with TVR and other grid modernization investments can facilitate load shifting from high demand periods to lower or even negative load (i.e., excessive renewable DG generation) periods by enabling flexible demand. Examples of flexible demand include customer DR, EV charging, stationary energy storage, smart appliances including thermostats, and perhaps in the future, electric vehicle-to-grid discharging. This shifting of energy consumption between time periods can reduce customer energy costs, avoid distribution system costs, and maximize renewable generation utilization. The Enhanced Load Shift sensitivity quantifies improved utilization of renewable generation and reduced buildout of the distribution system. However, impacts of this large a load shift on customer energy prices were not quantified due to a number of uncertainties at this time. However, enhanced load shifting is expected to reduce customers' energy costs beyond the energy cost reductions due to the smaller amount of load shift quantified in the base case AMF results.

Improved Short-Term Forecasting for Operations due to Granular Data: Better forecasting and monitoring of load, generation, and grid performance enabled by AMF, ADMS (i.e., ADMS-based load forecasting application), Advanced Field Devices, and DERMS can enable grid

[86] The existing standalone VVO/CVR platform is switched off when the grid is operating in an abnormal configuration.

operators to actively manage grid demand and grid supply maximizing asset utilization and allow dispatch of a more efficient mix of generation and ancillary services (e.g., spinning reserve, frequency regulation)[87] and reduce transmission congestion[88] to reduce generation and transmission costs, and ultimately, reduce electricity procurement costs on behalf of customers. Improved forecasting and monitoring of load and generation may also allow for less restricted DER operation in areas susceptible to system voltage or thermal constraints and allow NWA assets to be utilized for other beneficial uses if the grid operator can forecast that it does not need the NWA for reliability needs during a certain time period.

Reduced System Loss due to Shift to Local Generation Sources: Load Optimization and Reduced DG Curtailment through AMF, Advanced Reclosers & Breakers, ADMS, and DERMS can reduce the costs to interconnect and operate DG, which will enable more DG and help locate electricity production closer to the load rather than relying on bulk energy generation. This close proximity of generation to load will reduce transmission line losses for a given load served, and ultimately, could reduce electricity procurement costs on behalf of customers.

Reduced System Losses due to Optimized Reactive Power Control: Improved voltage management enabled by AMF, Advanced Field Devices, ADMS, and VVO/CVR and the ability to dispatch reactive power through DERMS and customer smart inverters, can improve the power factor of the system, including remote ends of the feeder. This may help reduce distribution system losses compared to less granular power factor correction using traditional methods such as a limited number of line capacitors.

In addition, the current method to addressing voltage issues due to DERs is setting a fixed absorbing power factor. This functionality can be extremely helpful but is limited in the fact that it is always absorbing reactive power at a fixed rate even at times when the system doesn't need it. Today, the reactive power absorbed often comes from a transmission source, which results in losses in the system. With investments in DERMS and the ability to adjust power factor settings dynamically using customer owned smart inverters,[89] reactive power absorption would only occur when needed, which can decrease losses in both the DG inverter output power and generating transmission-sourced VARs.[90] EPRI has done some work to quantify this value, but the value is highly dependent on location of the DER on the feeder and the penetration of DER on that feeder. Given the complexity of these calculation and the early stage of its development, the Company has not quantified this benefit in the GMP.

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[87] Ancillary services are necessary to ensure the reliable and efficient operation of the grid.

[88] Grid modernization enables this benefit either by providing lower cost energy or allowing the grid operator to manage the flow of electricity around constrained interfaces.

[89] Smart inverter power factor adjustments can be made seasonally or based on a Volt/Volt-Ampere Reactive (VAR) function where reactive power is injected based on voltage.

[90] Electric Power Research Institute, *Tailoring IEEE 1547 Recommended Smart Inverter Settings Based on Modeled Grid Performance* (December 2020). https://www.epri.com/research/products/000000003002020102

Reduced Customer Outages due to Granular Data: The granular and more frequent operational and performance data collected from AMF, Advanced Field Devices and ADMS, will help the Company determine the asset health of equipment and identify where maintenance should be performed and may help detect asset failures earlier, which would support condition based maintenance and mitigate possible equipment failure related outages. AMF meters will be capable of providing granular data that can be used to analyze equipment performance such as transformer health analysis. This will be achieved through ongoing investment and future expansion of the Data Management investments which includes data capture and storage, data backhauling requirements, analytics tools, and system integration. In addition, AMF provides granular outage data at the customer level, increasing the accuracy of fault location capabilities of ADMS, which can improve the isolation and restoration capabilities of FLISR.

Reduced Customer Outages due to OpTel Network Refresh: Much of the telecommunications equipment in the field and at substations are near the end of the product's useful life. With age, the reliability of electronics deteriorates. Equipment failure during normal operation poses operational risk and the impact of an unexpected outage is introduced. With advances in network technology and modern manufacturing, the new equipment is designed and built for greater longevity and higher mean time between failure (MTBF). See also *OPEX Labor Efficiency due to OpTel Network Refresh* in Section 8.6.1, above.

Improved Restoration Times due to Mobile Dispatch: ADMS-based Mobile Dispatch will interface with OMS and allow field crews with handheld devices to assign and dispatch themselves to outages based on their location, capabilities, and equipment. This can result in more efficient utilization of field crew time and shorten outage response time. The proposed Mobile Dispatch pilot project included under the ADMS category of investment includes a limited deployment of mobile dispatch capabilities to select field personnel, with a view to explore options to improve the outage restoration process. Learnings from the pilot will be applied towards developing the de-centralized process flows and requirements for a full deployment.

Improved Storm Recovery due to Granular Data and Distributed Automation: While a reliability benefit was quantified for outages, based on SAIDI and SAIFI reductions from Advanced Reclosers & Breakers and FLISR, the quantified benefit does not include outages due to major storm events. However, granular data and improved situational awareness due to the expansion of both monitoring and control from Advanced Field Devices, supported by ADMS and other grid modernization investments, allows for quicker fault location confirmation and the ability for the system operators to remotely sectionalize faulted areas, reconfigure, and restore customers outside fault areas before field crews arrive on site during storm-related outages. Automation of these remote control capable devices via a centralized program like FLISR will allow for the identification of a faulted area and the automated restoration of customers can provide additional reliability benefits, which have not been quantified to date.

Improved Resilience due to Situational Awareness and Distributed Automation: Resilience is the ability to continue operate and deliver power even during a low probability, high-impact disruption (e.g., hurricane, earthquake, cyber attack) by managing and minimizing potential consequences that occur as a result of the disruption. Many of the grid modernization investments will improve resiliency, including the ability for AMF to enable automatic outage detection and service restoration; Advanced Field Devices and FLISR to enable rapid detection, isolation and restoration of service via remote or automated control further reducing field personnel exposure during high impact events; Underlying IT Infrastructure to enable data management to find opportunities for further resilience improvements; and Appropriate Cyber Services to reduce the likelihood of a cyber-attack and quickly recover if an attach occurs.

Improved Customer Satisfaction due to Outage Notification: Currently outages are typically discovered when customers call in and report an outage at their homes. The improved situational awareness resulting from AMF, Advanced Field Devices and ADMS are likely to reduce or even eliminate the need for customers to call and report an outage. Instead customers can be notified on their cell phones directly when an outage occurs, this is likely to improve overall customer satisfaction and peace of mind. This will also help customers avoid the need to troubleshoot and investigate an outage during extreme weather conditions.

Grid Modernization Performance Benefits due to Reliable OpTel Private Network: The proposed OpTel Strategy will enable greater network control, performance and availability (uptime) than what commercial telecommunications carriers provide. The current Telecommunications model, which relies heavily on network connectivity provided by commercial carriers, lacks full visibility and understanding of the Company's network performance and outage. The Company must rely on outside service providers to design, maintain and repair the network, removing elements of control and direction over both network design and operation. Often, these companies fall short on embracing the criticality of a utility's stringent communication network requirements. Only in operating a private wireless network can total control be accomplished to the highest levels of availability.

8.6.3. Societal Benefits

Economic and Environmental Benefits due to DER Integration: DER development has driven significant job and GDP growth throughout the United States, as well as here in Rhode Island. Planning, installation, and financing DER projects employs a significant workforce in the State. The suite of grid modernization investments described in the GMP will help reduce the costs and other barriers to interconnect new DERs in Rhode Island, which will drive more DER investment in the State as opposed to outside of Rhode Island. See *Improved DER Experience due to DER Integration* discussion above. Note that this qualitative benefit is different than the Economic Development benefit that was quantified by the Company as a sensitivity analysis. The Economic Development benefit is based on the estimated state-level GDP improvement from the GMP investments themselves, as opposed to the indirect benefits from increasing DER growth in the State.

Likewise, DER development is an important driver for meeting clean energy goals and reducing GHG and criteria pollutant emissions, both of which have a significant environmental and health benefits to society and Rhode Islanders in particular.

Reduced Damage from Wide-scale Blackouts due to Situational Awareness: Improved situational awareness and control from AMF, Advanced Field Devices, ADMS, and FLISR can give grid operators a clearer picture of real time demand and supply as well as near term future supply and demand on the distribution grid which can allow transmission operations better coordinate resources and operations between regions. This can reduce the probability of wide-scale regional blackouts in times of limited capacity or limited transmission assets.

Improved Grid Stability and Data Protection due to Cyber Security: As shared in the Implementation Plan document, investing in cyber security helps the Company avoid several risks that may impact grid stability, which includes avoiding wide-scale blackouts. In addition, investing in Data Security will help the Company better protect customers' personal data. These risks can be extremely costly to the Company, its customers, and the State, but they are very difficult to quantify.

9. Conclusion

This GMP explains the need for cost-effective grid modernization solutions to address electric distribution system issues caused by increasing customer DER adoption, customers' evolving expectations, and State clean energy goals. It also demonstrates that the quantitative BCA for the Full Grid Mod Case investments results in hundreds of millions of dollars in net benefits for Rhode Island on a 20-year NPV basis, and all scenarios and alternative formulations evaluated resulted in benefit-to-cost ratios well above one. Additional qualitative benefits evaluated and described above only add to the quantified value.

The Company will be held accountable for progressing grid modernization solutions by implementing a flexible plan with the appropriate oversight and transparency. Accountability measures will include annual reporting of key metrics, PUC review and approval of future rate case and annual ISR investments, and continued engagement with the GMP and AMF Subcommittee. These measures will ensure the Company will be held accountable for deploying effective solutions and realizing customer benefits in a timely manner. The Updated AMF Business Case also provides its own portfolio of reporting, risk management, and benefits guarantee for the AMF investment.

Transforming Rhode Island’s electric distribution system is a journey that will take time and that must be undertaken in a thoughtful and strategic manner. It is important to take the next concrete step in the journey now to ensure that the electric grid does not hinder customer empowerment and does not create higher costs in the long run.

Grid Modernization Plan (GMP)

Implementation Plan

Table of Contents

1. Overview

This document presents the implementation plans for each solution that create the Grid Modernization Plan (GMP) portfolio. Each section in this document summarizes the Company's current plans for a particular solution and includes the following information:

- **Background:** Current state of technology, current limitations, and why the solution is needed
- **Goals and Objectives:** What the Company plans to accomplish for each solution
- **Benefits**: Summary of the key benefits of the solution
- **Schedule:** When the planned tasks and/or actions will occur
- **Status**: Summary of work completed to date
- **Major Tasks:** Planned tasks and/or actions
- **Cost Estimate:** High-level summary of expected capital expenditures (CAPEX), operating expenditures (OPEX), and run-the-business (RTB) costs over the next 5 years

This Implementation Plan (Plan) is a living document that will be reviewed and updated on an ongoing basis. Some plans that represent nearer-term investments are more detailed, while others, that represent longer-term investments, are less detailed at this time owing to the earlier stage of development. Plans and cost estimates will be refined over time, and the closer an investment gets to implementation, the more detailed and precise the plan and cost estimate will become.

Each actionable plan contained within this document has been written by subject matter experts within the Company, whose organizations support deploying and achieving grid modernization in Rhode Island. Additional details on the roles and responsibilities and management approach are presented in *Section 6: Accountability* of the GMP Business Case.

<u>Benefit Summary</u>

As explained in the GMP Business Case, all solutions are interrelated to each other and enable various benefit impacts. Table 1.1 summarizes how each of the GMP solutions interrelate, and how they enable various benefit impacts, which have been qualitatively (Q) or quantitively ($) addressed in *Section 8: BCA Evaluation Under Docket 4600* of the GMP Business Case. Table 1.1 also illustrates the primary solutions that provide each benefit impact, which are highlighted in green to recognize those solutions providing the most direct benefit impacts. As can be seen, there are some solution categories, including Underlying IT Infrastructure and Appropriate Cyber Services, that are not labeled as primary solutions, because they do not have direct benefit impacts themselves, but they are necessary to enable most, if not all, benefit impacts through other GMP solutions.

Table 1.1: Dependencies Between GMP Solutions and Benefit Impacts

GMP Solution / Benefit Impact Area	Avoided O&M Costs		Avoided Capital Costs		Customer Empowerment			Customer Energy Savings		Customer Reliability Improvements		Avoided Bulk Energy Purchases
	OPEX Labor Efficiency	Avoided Legacy OPEX Investments	Avoided Legacy CAPEX Investments	Avoided D-System Infrastructure	Improved Customer Choice & Control	Improved DER Experience	More Equitable Cost & Benefit Allocation	Reduced Customer Energy Use	Reduced System Capacity Requirements	Reduced Outage Notification Time	Reduced Outage Restoration Time	Reduced DG Curtailment
AMF Remote Metering	$	$	$	$	Q	Q	Q	$	$	$	Q	$
AMF Customer Information					Q			$	$			
AMF Advanced Pricing					Q	Q	Q		$			$*
System Data Portal					Q	Q						
Feeder Monitoring Sensors	$			$	Q	Q	Q	$	$		$	$
Advanced Capacitors & Regulators	$			$	Q	Q		$	$			$
Advanced Reclosers & Breakers	$			$	Q	Q		$	$		$	$
GIS Data Enhancements	$	$		$	Q	Q	Q	$	$	$	$	$
ADMS	$	$		$	Q	Q	Q	$	$	$	$	$
Underlying IT Infrastructure	$	$		$	Q	Q	Q	$	$	$	$	$
Appropriate Cyber Services	$	$		$	Q	Q	Q	$	$	$	$	$
Telecommunications	$	$	$	$	Q	Q	Q	$	$	$	$	$
VVO/CVR Platforms		$		$				$	$			
FLISR App (ADMS-based)											$	
DERMS		$		$	Q	Q	Q		$			$
ITR Projects	Q	Q	Q	Q	Q	Q	Q	Q	Q	Q	Q	Q

*Quantified as a sensitivity analysis only.

Note: solutions that contribute to a quantified benefit impact are denoted with a "$", and solutions that contribute to a qualified benefit impact are denoted with a "Q". Primary solutions contributing to each benefit impact are highlighted in green to recognize those solutions providing the most direct benefit impact.

Cost Summary

The five-year cost estimates for each GMP solution are provided in Tables 1.2 and 1.3 for the High Distributed Energy Resource (DER) and Low DER customer adoption scenarios, respectively. The cost estimates include all the costs of deploying the grid modernization solutions, including CAPEX, OPEX, and RTB costs like software maintenance fees and equipment maintenance.[41] As shown, investments in AMF, Advanced Field Devices (i.e., Feeder Monitoring Sensors, Advanced Capacitors & Regulators, Advanced Reclosers & Breakers), Operational Telecommunications, and ADMS are the primary cost drivers for the first 5 years of the GMP. In total, the Company estimates investing between $332 and $374 million for all GMP solutions through fiscal year (FY) 2026, depending on customer DER adoption. These costs would be recovered through the Company's annual ISR filings, current and future rate cases, and potentially a separate AMF docket. Additional cost details for each solution are presented in the subsequent sections of this Implementation Plan document.

Table 1.2: GMP Solution Cost Estimate Summary – Full Grid Mod Case/High DER Scenario

Full Grid Mod Cost Estimate - High DER Scenario, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
AMF*	$ 21.24	$ 25.50	$ 88.34	$ 49.05	$ 7.54	**$ 191.67**
System Data Portal	$ 0.70	$ 0.70	$ 0.70	$ 0.70	$ 0.70	**$ 3.50**
Feeder Monitoring Sensors**	$ 0.51	$ 2.74	$ 2.80	$ 2.83	$ 2.87	**$ 11.76**
Advanced Capacitors & Regulators	$ 3.10	$ 9.35	$ 9.42	$ 9.43	$ 9.46	**$ 40.77**
Advanced Reclosers & Breakers	$ 1.57	$ 9.45	$ 9.52	$ 9.56	$ 9.60	**$ 39.70**
GIS Data Enhancements	$ 1.15	$ 1.29	$ 1.02	$ 0.64	$ 0.55	**$ 4.64**
ADMS	$ 5.14	$ 4.66	$ 4.38	$ 1.79	$ 1.00	**$ 16.98**
Underlying IT infrastructure	$ 1.74	$ 1.04	$ 0.96	$ 0.48	$ 0.44	**$ 4.65**
Appropriate Cyber Services	$ 0.82	$ 0.31	$ 0.14	$ 0.14	$ 0.14	**$ 1.55**
Operational Telecommunications	$ 11.58	$ 12.14	$ 8.50	$ 3.48	$ 2.97	**$ 38.67**
VVO/CVR Platforms	$ 0.84	$ 2.61	$ 2.90	$ 0.76	$ 0.76	**$ 7.86**
FLISR App (ADMS)	$ -	$ -	$ -	$ 0.00	$ 0.12	**$ 0.12**
DERMS	$ -	$ 2.00	$ 2.00	$ 2.00	$ 2.28	**$ 8.28**
ITR Pilot Projects	$ -	$ 1.00	$ 1.00	$ 1.00	$ 1.00	**$ 4.00**
Total	**$ 48.39**	**$ 72.78**	**$ 131.68**	**$ 81.87**	**$ 39.42**	**$ 374.14**

* Costs associated with Underlying IT Infrastructure, Cyber Security, and Operational Telecommunications for the incremental AMF investment are included in the AMF line item. The AMF costs correspond to a full year of spending for each of the five project years, and do not align with the respective fiscal year. Please see the Company's AMF filing for additional detail.

** A reduction in Feeder Monitoring Sensor costs is included as an avoided cost benefit for AMF rather than a reduction in cost between cases.

Table 1.3: GMP Solution Cost Estimate Summary – Full Grid Mod Case/Low DER Scenario

Full Grid Mod Cost Estimate - Low DER Scenario, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
AMF*	$ 21.24	$ 25.50	$ 88.34	$ 49.05	$ 7.54	**$ 191.67**
System Data Portal	$ 0.70	$ 0.70	$ 0.70	$ 0.70	$ 0.70	**$ 3.50**
Feeder Monitoring Sensors**	$ 0.51	$ 1.53	$ 1.56	$ 1.58	$ 1.60	**$ 6.77**
Advanced Capacitors & Regulators	$ 3.11	$ 5.21	$ 5.25	$ 5.25	$ 5.27	**$ 24.09**
Advanced Reclosers & Breakers	$ 1.57	$ 5.26	$ 5.29	$ 5.31	$ 5.33	**$ 22.77**
GIS Data Enhancements	$ 1.15	$ 1.29	$ 1.02	$ 0.64	$ 0.55	**$ 4.64**
ADMS	$ 5.14	$ 4.66	$ 4.38	$ 1.79	$ 0.95	**$ 16.93**
Underlying IT infrastructure	$ 1.74	$ 1.04	$ 0.96	$ 0.48	$ 0.44	**$ 4.65**
Appropriate Cyber Services	$ 0.82	$ 0.31	$ 0.14	$ 0.14	$ 0.14	**$ 1.55**
Operational Telecommunications	$ 11.58	$ 12.14	$ 8.50	$ 3.48	$ 2.97	**$ 38.67**
VVO/CVR Platforms	$ 0.84	$ 1.48	$ 1.64	$ 0.43	$ 0.43	**$ 4.83**
FLISR App (ADMS)	$ -	$ -	$ -	$ 0.00	$ 0.07	**$ 0.07**
DERMS	$ -	$ 2.00	$ 2.00	$ 2.00	$ 2.28	**$ 8.28**
ITR Pilot Projects	$ -	$ 1.00	$ 1.00	$ 1.00	$ 1.00	**$ 4.00**
Total	**$ 48.39**	**$ 62.11**	**$ 120.78**	**$ 71.86**	**$ 29.27**	**$ 332.40**

* Costs associated with Underlying IT Infrastructure, Cyber Security, and Operational Telecommunications for the incremental AMF investment are included in the AMF line item. The AMF costs correspond to a full year of spending for each of the five project years, and do not align with the respective fiscal year. Please see the Company's AMF filing for additional detail.

** A reduction in Feeder Monitoring Sensor costs is included as an avoided cost benefit for AMF rather than a reduction in cost between cases.

As shown, there is a significant variation in the cost of Advanced Field Devices (i.e., Feeder Monitoring Sensors, Advanced Capacitors & Regulators, Advanced Reclosers & Breakers) between the Low and High DER scenarios. This is due to the fact that the Company assumed a flexible plan of investments that will be reviewed and adjusted in the appropriate regulatory forums. For example, rather than having a rigid long-term (10-year) deployment plan for advanced field devices, the Company plans to deploy these devices on feeders where customer DER adoption is expected to create distribution system issues (i.e., voltage, loading, and/or protection), which can be addressed by grid modernization. In this way, the Company will proactively identify needs and manage the implementation of the plan so functionalities are delivered "just in time." This flexible approach will maximize the realization of net benefits and minimize the cost to ratepayers.

Therefore, the assumed number of customer adopted DERs in the future is an important exogenous variable in the GMP. In the Low DER Scenario, the Company assumes a slower adoption of DERs will drive a slower adoption of Advanced Field Devices each year, while in the High DER Scenario, the deployment of Advanced Field Devices would need to increase rapidly to address the larger number of system issues expected to be caused by the higher adoption of DERs. Details are presented in *Section 5: Advanced Capacitors & Regulators*.

2. Advanced Metering Functionality (AMF)

Background

Advanced Metering Functionality (AMF) is a foundational component of the GMP. As stipulated by the 2018 Amended Settlement Agreement (ASA),[1] the Company has developed an Updated AMF Business Case to be filed in conjunction with this GMP for consideration and approval by the PUC. The Updated AMF Business Case includes a comprehensive BCA, which is consistent with the benefit-cost framework that the PUC adopted in its Report and Order in Docket No. 4600 (Docket 4600 Framework)[2] and the PUC's Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company d/b/a National Grid (Docket 4600 Guidance Document).[3] The Updated AMF Business Case includes a request for cost recovery, full implementation and program management plans, detailed data governance and customer engagement plans, metrics and performance incentive mechanisms, and a time-varying rate (TVR) overview.

For additional detail on AMF functionalities and how they integrate with the GMP to enable customer empowerment, increase system efficiency, support resource diversity, and better support integration of distributed generation (DG), please reference *Section 7: AMF Roadmap and Grid Modernization Integration* of the GMP Business Case.

Goals and Objectives

The Company proposes full-scale deployment of AMF meters to its electric customers over three-and-one-half years and ultimately to its gas customers over 10 to 15 years as their metering is upgraded through the normal course of business and subsequently integrated into the AMF network. Full deployment includes:

1) An integrated network of smart electric meters and gas modules capable of capturing customer energy usage data at defined intervals and supporting grid-edge applications;
2) Two-way communications network and related information technology (IT) infrastructure for transmitting the data and control signals that utilizes radio frequency and cellular communications technology;

[1] Amended Settlement Agreement, Docket Nos. 4770 & 47780, Report and Order No. 23823 (May 5, 2020), http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-ComplianceFiling-Transmittal%20(August%2016,%202018).pdf;
[2] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates In Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 (July 31, 2017).
[3] *See Pub Util. Comm'n Guidance on Goals, Principles and values for Matters Involving the Narragansett Elec. Co. d/b/a National Grid*, Docket 4600-A (October 27, 2017) [hereinafter Docket 4600 Guidance Document].

3) A meter data management system (MDMS), head end system (HES), IT platform, and cyber security protections to securely and efficiently collect, validate, store and manage the meter data; and
4) Customer systems including billing and the Customer Energy Management Platform (CEMP) to provide energy usage data access, insights, and service offering to enable customer energy management.

At the customer level, AMF technology will capture and transmit energy usage data through a wireless communications network. This same information can also be communicated to in-home/business devices directly from the electric meter. A network of communication devices will be strategically placed throughout the service territory to collect meter data and transmit the data through a backhaul network to the Company. The head-end system then processes the data before it is transmitted to the MDMS, which performs data validation and generates the appropriate billing determinants for each customer. This data will be processed by the Customer Service System for billing and delivered to the CEMP, which will provide customer and authorized third parties with access to energy consumption data, energy insights, and service offerings.

The Company's AMF solution proposal provides access to energy usage information for all customer classes through three primary channels: 1) the CEMP, 2) Green Button Connect My Data (GBC) that will be accessible from the CEMP, and 3) directly from the meter through a customer's home-area-network (HAN). The first two channels, CEMP and GBC, require meter usage data transmission from the meter, through the end-to-end AMF solution, to the data sharing platforms in the CEMP. Through this data process, the company will provide access to 15-minute electric data at a 30- to 45-minute latency and hourly gas data at an eight-hour latency. Customers will have access to the CEMP through the web and their mobile devices. The third channel provides optionality for customers to obtain real-time usage data directly from the meter through a HAN. Electric AMF meters contain a physical radio and associated firmware to provide a wireless signal to HAN devices for data transmission. Similar to how some WiFi enabled electronic devices are connected in homes today through a wireless router, meters can be paired[4] with in-home devices that customers or third parties deploy to share and display customer data in real time. Customer data can also be made available to customers' mobile devices, leveraging HAN and third- party internet-based service offerings. A description and data latency parameters for each of the channels are provided in Table 2.1 below.

[4] For a customer to connect a HAN-related device to an AMF meter, the customer will first confirm the eligibility/compatibility of the device with the AMF meter and then activate the device by logging into their secure online account on the CEMP. Once logged in, the customer will navigate to the activation page, enter the applicable device credentials, and receive an activation acknowledgment through encrypted channels. From there, the customer may begin using his or her HAN device, such as an in-home display or home energy manager.

Table 2.1: Customer Data Access Latency

<table>
<tr><th>Data Access Channel</th><th>Description</th><th>Data Latency</th></tr>
<tr><td>Customer Energy Management Platform (CEMP)</td><td>Enables access to customers' own usage data directly and ability to download it for sharing with third parties</td><td rowspan="2">• For electric customers, 15-minute raw interval data will be available every 30-45 minutes
• For gas customers, one-hour raw interval data will be available every eight hours
• This same information will be available at bill quality[5] data within 24 hours</td></tr>
<tr><td>Green Button Connect (GBC)</td><td>Facilitates computer-to-computer communication to allow for a standard protocol by which authorized third parties can have direct access to a customer's data upon customer authorization</td></tr>
<tr><td>Meter to Home-Area-Network (HAN)</td><td>Transmits data directly from meter to HAN</td><td>• Real-time raw energy usage data</td></tr>
</table>

The AMF solution also includes remote metering capabilities, such as remote interval meter reading and remote connect and disconnect functionality. These capabilities improve operational efficiency by enabling the Company to reduce operations and maintenance (O&M) costs associated with Automated Meter Reading (AMR), as well as investigations and visits to connect and disconnect service. This will improve several aspects of the customer experience and simplify tasks such as the move-in/move-out process.

Additionally, AMF provides customer and DER level interval energy usage information required to support advanced pricing. This will allow for innovative rate designs that can better accommodate and integrate DER by sending more accurate price signals to customers. These price signals will improve performance of customer load management programs, which can be used to shift energy consumption between time periods to reduce energy costs and/or alleviate location specific constraints on the delivery system. Customers can then use this information to make informed choices that are beneficial to themselves, as well as to the electric grid. For example, an electric vehicle (EV) customer can choose to charge a vehicle during off-peak times, when it is less expensive to do so and when the system has ample capacity, as reflected by lower off-peak costs.

Benefits

AMF primarily provides Remote Metering, Customer Information, and Advanced Pricing functionalities, while also supporting or enhancing a number of other key functionalities, including Observability (Monitoring and Sensing), Power Quality Management, Distribution

[5] To generate "bill quality" data, a series of validation, estimation and editing functions are performed on the raw data.

Grid Control, Grid Optimization, and DER Operational Control.[6] AMF's primary functionalities result in a number of quantified benefit impacts that are summarized below.

Remote Metering

- OPEX Labor Efficiency:
    - Avoided costs of AMR meter reading vehicles and personnel
    - Avoided costs of meter investigations, visits to connect and disconnect service, and service-related damage claims
    - An outage management operational benefit that quantifies Company O&M savings due to storm restoration efforts being more streamlined with more accurate data from AMF

- Avoided Legacy OPEX Investments
    - Avoided AMR annual software maintenance fees

- Avoided Legacy CAPEX Investments:
    - Avoided costs of AMR hardware replacement and installation, which are approaching end of life
    - Avoided costs of associated with the continued operation of the current interval meter system for large commercial and industrial customers (e.g., MV-90 interval meter)
    - Avoided Feeder Monitoring Sensor costs due to enhanced feeder monitoring enabled by AMF

- Improved DER Experience by providing the interval energy and voltage data at the customer level required for verification and settlement of DER services provided to or received from the grid. AMF also enables the exchange of information and/or control with in-home, business, or grid-connected DER technologies. In the future, this will provide new opportunities for automated responses to TVRs. Included as a qualitative benefit only.

- Reduced Customer Energy Use due to an incremental improvement (additional 1% energy reduction) from volt-VAR optimization/conservation voltage reduction (VVO/CVR) using AMF granular voltage data when coupled with Advanced Capacitors & Regulators, VVO/CVR platform, and other supporting solutions.

- Reduced Outage Notification Time (when coupled with ADMS) by integrating AMF-based autonomous outage notifications alerting the Company to trouble before receiving

[6] Descriptions of each functionality are provided in *Section 5.5: Functionality and Benefit Impacts Assessment* in the GMP Business Case and in the Appendix document.

customer outage calls. Integrating this functionality with the Company's Outage Management System (OMS) will reduce time from initial outage to Company notification, and enhance the Company's overall outage response capabilities.

Customer Information

- Reduced Customer Energy Use and System Capacity Requirements as a result of customer action based on enhanced energy use insights (e.g., AMI-based High Bill Alerts), integrating AMF with in-home energy saving technologies (e.g., in-home displays, smart appliances), and responding to TVR to reduce demand for energy during peak demand periods (Reduced System Capacity Requirements only), including reductions in EV charging during peak periods.

Advanced Pricing

- Reduced System Capacity Requirements as a result of customer action based on responding to advanced pricing to reduce demand for energy during peak demand periods, including reductions in EV charging during peak periods. Advanced pricing encourages customers to shift charging of EVs from on-peak to off-peak periods using critical peak pricing (CPP) or other TVR structures.

- Reduced DG Curtailment:[7] Advanced pricing encourages customers to shift demand to negative load periods when renewable power is most abundant (i.e., 7 am – 3 pm for solar PV) under high customer DER adoption scenarios.

AMF's primary functionalities also result in a number of important qualitative benefit impacts that are summarized below.

Customer Information

- Improved Customer Choice & Control by enabling improvements in customer energy usage information sharing, third-party information sharing, and access to third-party service providers, which empowers customers to better understand and prioritize among solutions to best manage energy usage and costs. When paired with Advanced Pricing, customers will have the opportunity to respond to price signals and achieve even greater savings.

[7] Quantified in a sensitivity analysis only.

Advanced Pricing

- Improved DER Experience due to the ability to more precisely monetize the value of DER to the system, which can improve the economics for DERs.

- More Equitable Cost & Benefit Allocation due to the ability to more precisely monetize the value of DER to the system, which will enable the associated DER value to be more representative of its costs and benefits to the grid. This will permit more effective customer programs, such as more effective DR programs for peak load reduction or energy storage for excess renewable energy utilization.

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or described qualitatively in *Section 8.6 Qualitative Assessment* of the GMP Business Case. More detailed AMF benefits are presented in the Updated AMF Business Case filing.

Schedule

The Company proposes a three-and-one-half year AMF meter deployment program as shown in Figure 2.1. Phase one, which covers the first two years following regulatory approval and a managed project ramp up, will address detailed design, remaining procurement activities, and the installation and upgrade of the back-office systems. Phase two, which would begin in the last quarter of phase one and run for approximately one year, focuses on deploying the communication network. Phase three, which would commence after the completion of phase one, involves the deployment of electric AMF meters over an 18-month period. As further illustrated by the arrows in the bottom of the figure, the Company also plans to employ a robust Customer Engagement Plan with activities occurring pre, during, and post meter deployment. The Company has also provided an illustrative view of the anticipated timeline for development, approval, and implementation of TVR as part of a separate docket. Additional detail on those activities, as well as data governance, program management, reporting, metrics and risks can be found in the Updated AMF Business Case filing.

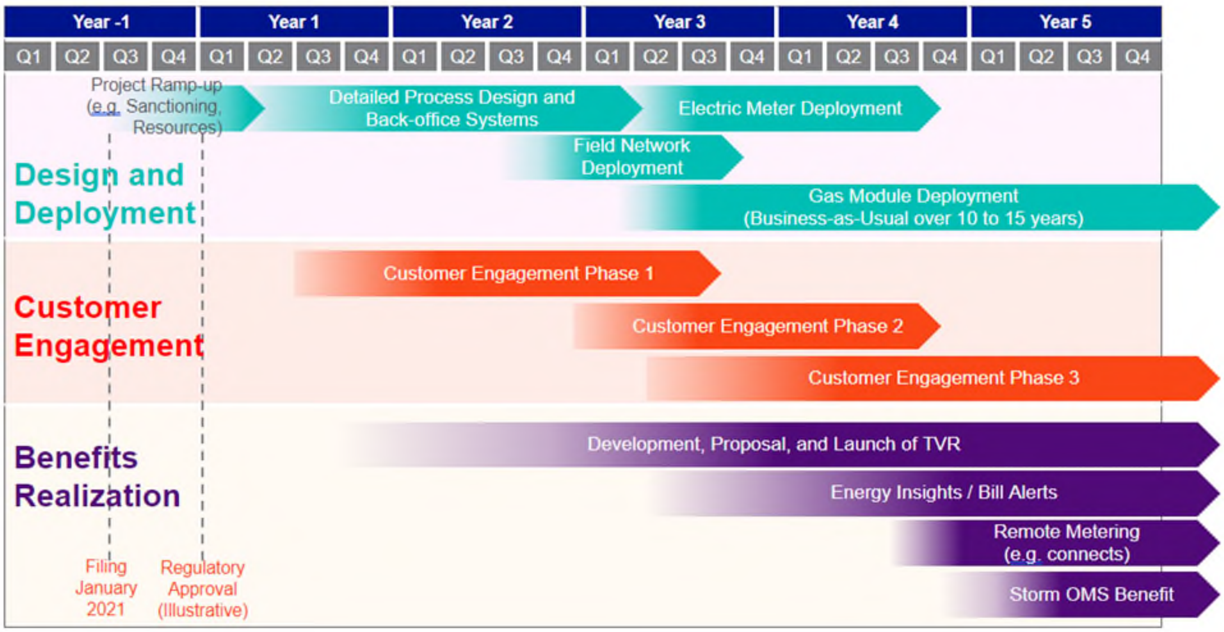


Figure 2.1: Illustrative Rhode Island AMF Deployment Timeline

Status

The Company has refined and updated the AMF Business Case as part of the ASA based on extensive feedback from the GMP and AMF Subcommittee of the PST Advisory Group, updated Company forecasts and research, updated cost inputs from the Company's Request for Solution, and the expanded application of the Docket 4600 Framework, among other things. Subcommittee feedback was gathered through a series of stakeholder collaboration meetings which ran from late 2018 to late 2020 and stakeholder review of materials during that time. Feedback from the Subcommittee was used to enhance all components of the AMF proposal (e.g., Updated AMF Business Case, AMF BCA, and all supporting attachments).

Major Tasks

In the updated AMF Business Case, the Company categorizes key cost elements into the four segments below. More detailed information can be found in Section 8.3 of the Updated AMF Business Case.

1. *AMF Meter and Installation Costs*
   This category includes the cost of smart electric meters, their installation, an inventory of meters, and the necessary support infrastructure. Gas module roll-out will follow the timeline of business-as-usual gas meter replacement. Thus, gas module costs fall within the ISR filing and the incremental cost of the AMF-enabled gas modules is zero. Because

this incremental cost is zero, there is no BCA element associated with the purchasing or installation of gas modules.

2. *Communications Network Equipment and Installation Costs*
   This category includes the communications network equipment, its installation, and the associated backhaul network costs for transmitting meter data.

3. *Platform and Ongoing IT Operations Costs*
   This category includes the total cost of an IT platform for data collection, monitoring and control of the communication system; an expanded cyber security system; MDMS and HES; an analytics platform to convert raw data into intelligent information for use in decision making by customers and the Company; and customer engagement solutions.

4. *Customer Systems including Billing and CEMP Costs*
   This category includes the cost of customer systems: comprehensive customer engagement, project management, ongoing business operations, equipment and installation refresh, and TVR implementation and administration.

Cost Estimate

Table 2.2 presents the 5-year cost estimates for the “AMF Opt-out, RI+NY” option described in detail in the Updated AMF Business Case filing. Additional cost estimates for other options are presented in the Updated AMF Business Case filing. The Company estimates investing $192 million through the first five years of the project. The costs would be recovered through the Company’s rate case filings or through a separate AMF docket. Note that the Company also performed planning work from FY 2019 through FY 2021 to ensure the Company is fully prepared to execute the projects. This work is being performed utilizing existing resources in the current Multi-Year Rate Plan (MRP). An overview of the work completed to date is provided in *Section 4.1: 2017 Rate Case Funding for Grid Modernization* in the GMP Business Case.

Table 2.2: AMF Cost Estimates for Opt-Out, RI+NY – 5-Year Plan

Advanced Metering Functionality, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot*
AMF Meter and Installation CAPEX	$ 0.10	$ 1.81	$ 68.12	$ 35.62	$ -	**$ 105.65**
AMF Meter and Installation OPEX	$ -	$ -	$ 1.80	$ -	$ -	**$ 1.80**
Communications Network Equipment and Installation CAPEX	$ -	$ 0.05	$ 2.06	$ 1.08	$ -	**$ 3.19**
Communications Network Equipment and Installation OPEX	$ -	$ -	$ 0.05	$ 0.08	$ 0.08	**$ 0.21**
Platform and Ongoing IT Operations CAPEX	$ 6.34	$ 5.18	$ 0.91	$ 0.57	$ 1.00	**$ 14.00**
Platform and Ongoing IT Operations OPEX	$ 4.66	$ 4.98	$ 4.57	$ 2.46	$ 2.53	**$ 19.20**
Platform and Ongoing IT Operations RTB	$ -	$ -	$ 1.19	$ 1.57	$ 1.32	**$ 4.08**
Customer Systems including Billing and CEMP CAPEX	$ 1.24	$ 8.57	$ 2.90	$ 2.33	$ 0.11	**$ 15.15**
Customer Systems including Billing and CEMP OPEX	$ 8.90	$ 4.92	$ 6.73	$ 5.34	$ 2.50	**$ 28.39**
Total	**$ 21.24**	**$ 25.51**	**$ 88.33**	**$ 49.05**	**$ 7.54**	**$ 191.67**

*The AMF costs correspond to a full year of spending for each of the five project years, and do not align with the Company's fiscal year. Please see the Company's AMF filing for additional detail.

3. Rhode Island System Data Portal

Background

The Company developed the Rhode Island System Data Portal (Portal) to promote the sharing of information with DER providers and others. The Portal provides relevant distribution planning information and electric distribution system data intended to encourage DER integration in the most advantageous and cost-effective locations. The Portal is a web-based application [8] and currently provides the following information.

- Company Reports: planning process and criteria, load forecasts, and completed distribution planning studies
- Distribution Asset Overview: geographic overview of distribution feeders including technical specifications of feeders and substations
- Heat Map: geographic representation of feeder loading

[8] The System Data Portal can be accessed online via National Grid's public landing page, https://www.nationalgridus.com/Business-Partners/RI-System-Portal

- Hosting Capacity: geographic representation of DER hosting capability by distribution feeder
- Sea Level Rise: identifying areas impacted by potential coastal flooding
- Non-Wires Alternatives (NWAs): link to National Grid's central NWA website which contains a list of NWA opportunities and any RFPs soliciting NWA solutions

Figure 3.1 presents a screen shot from the Heat Map tab on the System Data Portal. From this opening view the user can zoom to or select a specific location and get more detailed information.

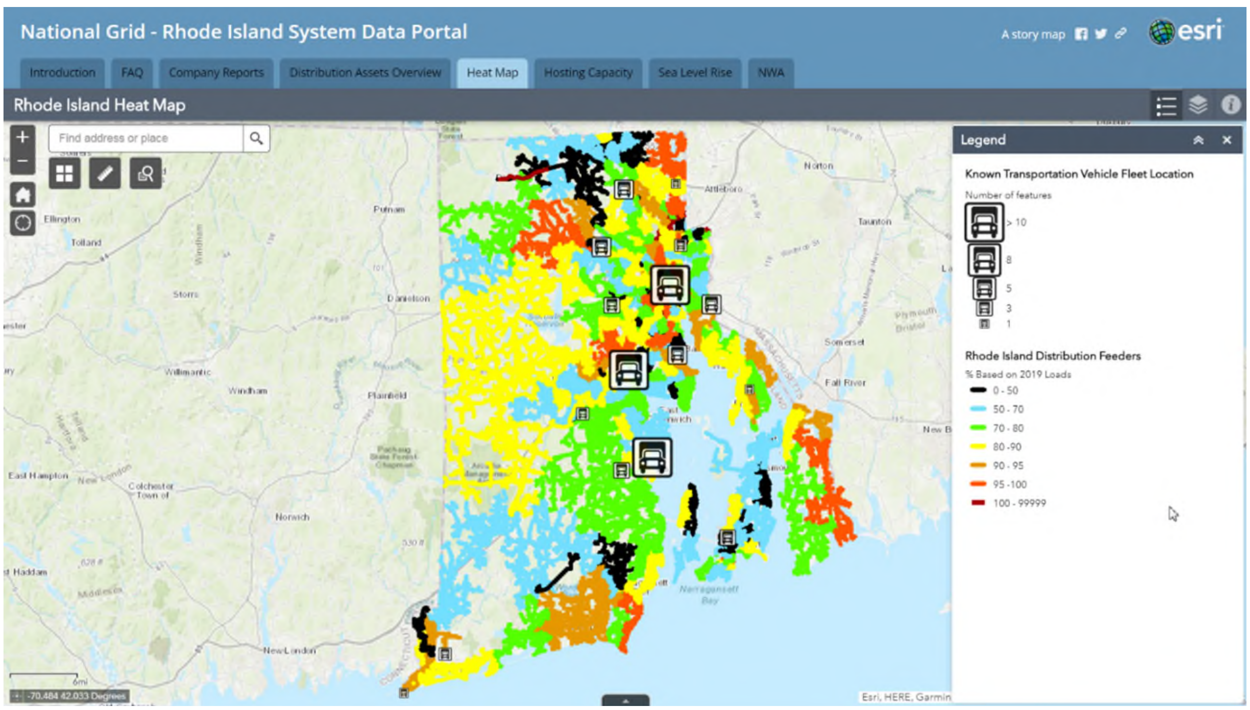


Figure 3.1: Rhode Island System Data Portal Heat Map View

The Portal is already in service. The initial version of the Portal was established through the Company's System Reliability Procurement (SRP) program and went live on June 30, 2018. Information on the Portal is refreshed periodically (i.e., monthly for some elements and annually for others) and is enhanced as new information becomes available. Stakeholder engagement and new enhancements to the Portal are proposed and funded through the SRP. Normal maintenance work and salaries of staff that support the Portal were included in the 2017 Rate Case.

Goals and Objectives

The Company considers the Portal to be an important investment to align with developers' and other stakeholders' desire for improved data and transparency to Company planning information. The content of the Portal is expected to expand and evolve over time as new tools, data, and analysis are developed. Determining what data to share on the Portal is a collaborative process. As the need for data sharing grows along with technological advancements and interest from third parties, the Company continues to collaborate with relevant stakeholders through SRP stakeholder sessions. The Company looks forward to additional collaboration and discussion with all interested parties to continue to explore future data sharing opportunities.

Benefits

The Portal primarily provides Distribution System Information Sharing functionality, meaning it enables improved DER location selection, streamlined DER interconnections, and better customer and third-party information sharing and services by showing customers and DER providers where potential cost-effective interconnection locations are on the distribution system. [7]

This functionality creates two qualified benefit impacts: Improved Customer Choice & Control and Improved DER Experience. The Portal will achieve these two qualified benefit impacts by clearly communicating to customers and third party DER markets where and when DERs provide the most value to the grid and are likely to have lower costs and other barriers to interconnect. This will help optimize existing DER investments, facilitate new ones, and enhance DER offerings, increasing the value of programs including DG, energy storage, EV, EHP, DR, and enabling customers to better prioritize among solutions. Although studies are still required, the Portal information facilitates DER siting in grid-beneficial locations through non-price signals with the aim of reducing distribution system costs and lower rates for customers. The Portal's benefits support objectives and goals that span multiple efforts, including the Docket 4600 Guidance Document, National Grid's Net Zero by 2050 Plan, and the GMP's third objective to "build a flexible gird to integrate more clean energy generation".

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or described qualitatively in *Section 8.6 Qualitative Assessment.*

Schedule

The Company anticipates a continued sustained investment in the Portal through 2030 to maintain and expand the Portal's capabilities over time based on stakeholder engagement through the SRP and presentations to the local DER community.

Status

The Portal is already in a mature state. The Company recovered the costs for tasks associated with the Initial Version of the Portal, and the Initial Version of the Hosting Capacity Map through the 2018 SRP Report filing. The Company is currently recovering operational and maintenance expense for full implementation and continued support costs for the Portal through base distribution rates approved as part of the ASA in Docket No. 4770. The Company added two full-time equivalents (FTEs) to its workforce in Rate Year 1, including one incremental FTE in the Asset Data & Analytics group in December 2018 and one incremental FTE in Distribution Planning & Asset Management in June 2019.

Major Tasks

National Grid will continue to maintain and enhance the Portal's hosting capacity maps. The Portal currently displays several distribution system parameters, including voltage class, feeder load, level of interconnected and proposed DG, substation 3V0 status, and maximum and a minimum hosting capacity value for each feeder analyzed. The Company is analyzing sub-feeder level hosting capacity information to be added into the maps to further increase the granularity of data and provide locational-specific information to better inform DG developers. Additionally, proposed future grid modernization compliance reports that include metrics intended to measure and enable a transparent assessment of the Company's progress and effectiveness of GMP implementation in key areas of interest to customers, regulators, and stakeholders, will be added to the Company Reports tab. Details are provided in *Section 6.2: Reporting Metrics* of the GMP Business Case.

The Company estimates continued employment of two FTEs to manage the Portal and one additional FTE to manage the development of future grid modernization compliance data and reports. The previously hired FTEs will work with the new FTE and other subject matter experts at the Company to continue to update information on the Portal.

Cost Estimate

Table 3.1 presents the 5-year cost estimates for the Portal investment. The Company estimates investing $3.5 million through FY26 for continued employment of two FTEs to manage the Portal and one additional FTE to manage the development of future grid modernization compliance data and reports. Support costs to manage the development of future grid modernization compliance data and reports will be recovered through the Company's future rate case filings. Enhancements to the Portal will be proposed through the SRP, although no new enhancements are currently planned.[9] An overview of the work completed to date is provided in *Section 4.1: 2017 Rate Case Funding for Grid Modernization* in the GMP Business Case.

Table 3.1: System Data Portal Cost Estimates – 5-Year Plan

System Data Portal, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
System Data Portal OPEX	$ 0.70	$ 0.70	$ 0.70	$ 0.70	$ 0.70	**$ 3.50**

4. Feeder Monitoring Sensors

Background

The dynamic impacts of DER on the distribution system's performance require a granular understanding of situational awareness to assure service is maintained within acceptable service quality standards in an efficient manner. In the absence of data, operators and distribution system planners must make conservative assumptions with respect to the coincidence of load and DER operation. This leads to more restrictive hosting capacity assessments and less than optimal operational actions. Feeder Monitoring Sensors (Sensors) provide more accurate data for hosting capacity and maximum loading (i.e., heat map) calculations, which benefit DG and other DER providers (e.g., EV charging stations) looking for the most economical locations for their projects. Without the proposed investment in Sensors, interconnection studies would require substantial limitations on future DER interconnection applications. In addition, the near real-time power measurements provided by these sensors enable the Company to better manage the distribution system, including better VVO/CVR strategies to benefit customers.

Goals and Objectives

Achieving the goals of the GMP will require interval monitoring on all primary distribution feeders, at least at the head of the feeder (i.e., at or near the substation) for compliance with voltage and protection requirements as customer DER adoption grows. The Company's standard practice for several years has been to deploy remote interval monitoring and control for new substations and feeders as part of the Company's Energy Management System (EMS) Program.[10] Substation interval power monitoring has been deployed on approximately 65% of feeders in Rhode Island, but progress has been slow on the remaining 35% of feeders because the remaining substations require additional work beyond simple EMS infrastructure. For this

[9] New enhancements are expected to originate from collaborative consultation between National Grid and external stakeholders.
[10] The Company's EMS Program is an effort to enable remote control and data acquisition on a variety of substation equipment (e.g., breakers, regulators, transformers), which can be managed by the Company's EMS.

reason, the Company has not installed a new substation interval power monitor since 2017, and there remain over 100 feeders without interval power monitoring or the ability to monitor performance remotely. Sensors are a cost-effective method of measuring current, voltage, and real and reactive power until this additional EMS work can be completed.

Therefore, the Company proposes to install Sensors to provide interval monitoring in concert with other Advanced Field Devices (i.e., Advanced Capacitor, Regulators, and Reclosers) to help manage capacity and voltage along individual distribution feeders. This will allow the distribution system to be operated in a more efficient manner and result in lower costs to all National Grid customers through optimization.

The Company has reviewed and tested multiple types and styles of Sensor packages. The three-phase equipment package the Company is currently pursuing includes line-post sensors built into post insulators on a pole top; a control relay (i.e., controller) for processing the voltage, current, and power quantities; and a cellular radio to wirelessly transmit the data back to the data concentrator located at the Company's Distribution Control Center. Figure 4.1 presents a summary of key feeder monitoring sensor components.

Figure 4.1: Feeder Monitoring Sensor Key Components

<u>Benefits</u>

Sensors provide Observability (Monitoring and Sensing) functionality, which enables system planners and operators to design and operate the distribution system in a more flexible and efficient manner. This functionality is a foundational element and supports all other key functionalities described in *Section 5.1.4: Functionality and Benefit Impacts Assessment* of the

GMP Business Case.[7] Power Quality Management functionality results in the quantified benefit impact summarized below.

- Reduced Customer Energy Use and System Capacity Requirements (when coupled with Advanced Capacitors & Regulators, VVO/CVR platform, and other supporting solutions) by enabling the system operator to manage voltage impacts of renewable DERs and operate distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption and peak demand from customer appliances

Sensors, in combination with other grid modernization investments, enable the Company to ensure voltage and loading compliance across all times of a year in areas of the distribution system with high levels of DER penetration. Voltage compliance and load management are fundamental utility requirements for safe and reliable electric service. However, the Plan allows these fundamental requirements to be integrated over time to maximize net benefits and realize new functionalities where and when they are needed.

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

Sensors will be installed at strategic points on a feeder to obtain real-time visibility into power quality. Sensor data will assist the Company in making sure the best technical decisions are recommended to benefit customers and grid assets. Estimated Sensor deployment schedules are included in the Schedule subsection within *Section 5.1.4: Advanced Capacitors & Regulators*.

Situational awareness will be augmented with information from field equipment other than Sensors, including advanced controllers that the Company has already begun utilizing on reclosers, capacitors and regulators. This consideration has informed and reduced the scope of these Sensors to head-end and remote-end sensors only. Also, AMF meters can provide interval power monitoring at the customer level or at remote-ends of the feeders. If AMF meters are deployed, Sensor deployment can be further reduced to head-end sensors only.[11] This scope reduction will be incorporated into the actual designs and final deployment schedules as they occur. The Company will present these updated designs for PUC approval through annual Infrastructure, Safety and Reliability (ISR) Plans. The Company believes it is important to have primary-level interval monitoring at least at the feeder head-end integrated with SCADA for compliance with voltage and protection regulations. Any monitoring needs downstream will consider the relative costs and benefits of primary monitoring, or the utilization of aggregated secondary monitoring through AMF.

[11] A reduction in Sensor costs is included as an avoided cost benefit for AMF rather than a reduction in cost between the Grid Mod Only and Full Grid Mod cases.

Status

The Company does not have any active programs to install Sensors specifically targeting areas with significant levels of DER penetration, where these capabilities can be leveraged to support the efficient operation of a distribution system with high amounts of DER. However, the Company has deployed 44 Sensors on 19 feeders from 6 substations in Rhode Island as part of the Company's VVO/CVR Pilot program. Deployment on an additional 14 feeders is anticipated through the Company's VVO/CVR program in the FY 2021 ISR Plan.

Major Tasks

The locations and specifications of field devices will first be proposed, scoped, and sanctioned based on area studies and cost-benefit estimates using Company forecasts and feeder-level information, including expected future DER interconnections, VVO/CVR energy savings, reliability improvements, and other customer benefits. Next, long lead-time equipment orders will be placed and the Company will work with equipment vendors to configure the field devices according to the specified requirements. Project Plans will include procurement, office testing, constructability reviews, training, installation, programming, field testing, and measurement and verification (M&V) of the full system.

Cost Estimate

Table 4.1 presents the 5-year cost estimates for the Sensor investment under the High and Low DER customer adoption scenarios. These costs are for the Grid Mod Only Case. In the Full Grid Mod Case, these costs would effectively be reduced by 67% due to the ability of AMF meters to replace two of the three sensors estimated for each feeder (i.e., two remote-end sensors). The Company estimates investing between $6.8 and $11.8 million through FY 2026, depending on customer DER adoption. The costs estimates shown include CAPEX, OPEX, and RTB costs including Telecoms RTB, which accounts for the cost of third-party cellular fees necessary to communicate with the device's radio.[12]

[12] Telcom RTB costs are gradually reduced starting in FY25 as the OpTel Strategy investments enable the Company to operate a private cellular network.

Table 4.1: Feeder Monitoring Sensors Cost Estimates – 5-Year Plan (Grid Mod Only Case)

Feeder Monitoring Sensors, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
High DER Scenario						
Sensors CAPEX	$ 0.46	$ 2.50	$ 2.50	$ 2.50	$ 2.50	**$ 10.44**
Sensors OPEX	$ 0.04	$ 0.24	$ 0.24	$ 0.24	$ 0.24	**$ 0.99**
Sensors RTB	$ -	$ 0.01	$ 0.05	$ 0.09	$ 0.13	**$ 0.28**
Sensors Telecom RTB	$ -	$ 0.00	$ 0.02	$ 0.01	$ 0.01	**$ 0.05**
Total	**$ 0.51**	**$ 2.74**	**$ 2.80**	**$ 2.83**	**$ 2.87**	**$ 11.76**
Low DER Scenario						
Sensors CAPEX	$ 0.46	$ 1.39	$ 1.39	$ 1.39	$ 1.39	**$ 6.01**
Sensors OPEX	$ 0.04	$ 0.13	$ 0.13	$ 0.13	$ 0.13	**$ 0.57**
Sensors RTB	$ -	$ 0.01	$ 0.03	$ 0.05	$ 0.07	**$ 0.16**
Sensors Telecom RTB	$ -	$ 0.00	$ 0.01	$ 0.01	$ 0.00	**$ 0.03**
Total	**$ 0.51**	**$ 1.53**	**$ 1.56**	**$ 1.58**	**$ 1.60**	**$ 6.77**

The investment estimate above covers a broad range due to the uncertainty in the level of customer DER adoption and the resulting distribution system issues. Therefore, the Company will present the actual deployment plan and request for cost recovery through the Company's annual ISR Plan filings.

5. Advanced Capacitors & Regulators

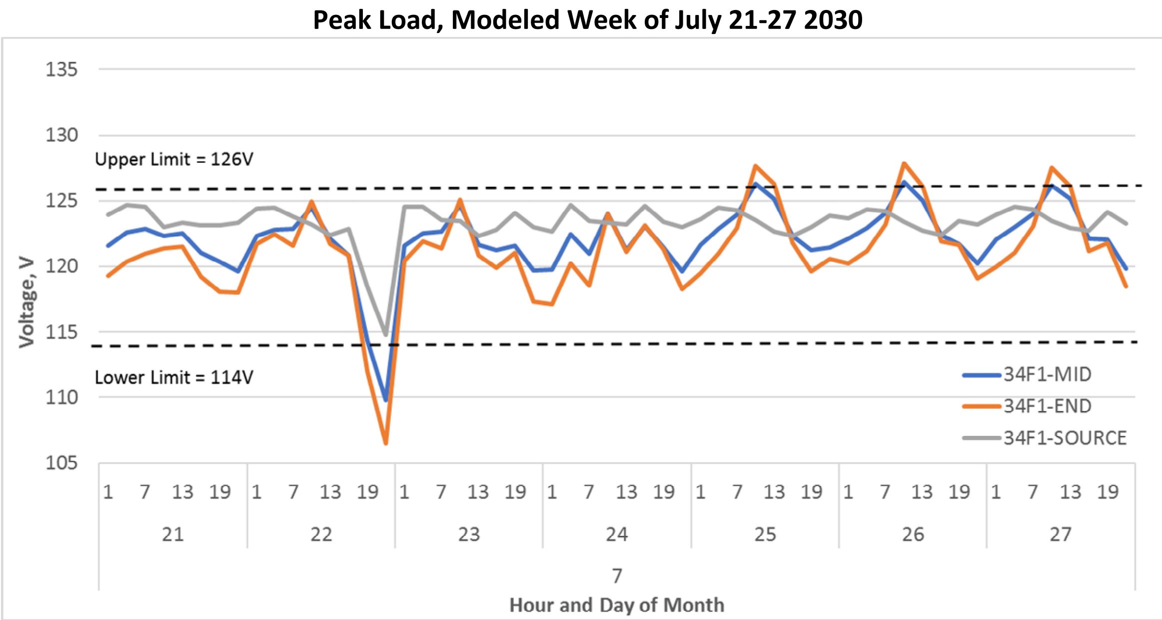
Background

For a customer's electrical equipment to operate as expected, it must be connected to a source that is operating within an allowable voltage range. Generally, acceptable voltages are +/- 5% of a defined nominal value. For example, nominal delivery voltage may be 120 volts for a residential customer with an acceptable range of 114 to 126 volts. Coincident voltages along the distribution system will vary by location on the feeder, and the voltage at any delivery point will also vary with time.

In the past, voltage regulation was relatively predictable. With one-way power flows, voltage tended to "drop" from the head-end of the feeder to the remote-ends of the feeder due to the resistance of the wires and the distribution of load along them. Key variables for distribution planners to consider in determining how much voltage drop to plan for were a feeder's load profiles and electrical impedance. To compensate for this voltage drop, capacitors and voltage regulators have traditionally been installed to boost the voltage to stay within the required voltage range. For capacitors, a planning rule of thumb was to install "Fixed" capacitors (which are always on) to accommodate the voltage drop at minimum load levels and "Switched" capacitors to compensate for voltage drops at peak load levels. Since electrical resistance of the system and the load cycles were very predictable, the control settings on capacitors and regulators were simple, autonomous, and only needed to be adjusted occasionally in concert with periodic planning reviews. An example of a simple time clock control is shown in Figure 5.1 along with a new programmable-type control unit.

Figure 5.1: Time Clock Control & New Programable Logic Control Components

However, these simple autonomous settings will be insufficient to maintain compliance with voltage standards for feeders with a high level of intermittent renewable DG and two-way power flows. Specifically, generation-based DERs, such as solar and wind DG, are forecasted to create overvoltage during light load periods, while load-based DERs, such as EV charging, are forecasted to create under-voltage issues during peak load periods. Figures 5.2 and 5.3 show examples of under-voltage and overvoltage issues forecasted by 2030 on specific Rhode Island feeders under the High DER Scenario. These voltage compliance risks are projected to be prevalent across seasons, months, weeks, and days in the future under both the High and Low DER scenarios. While the examples provided in Figures 5.2 and 5.3 present voltage issues the Company anticipates will be systemic by the year 2030, these issues are arising in isolated areas already. Likewise, voltage constraints are being identified in interconnection studies and are limiting hosting capacity for many new interconnection applications.



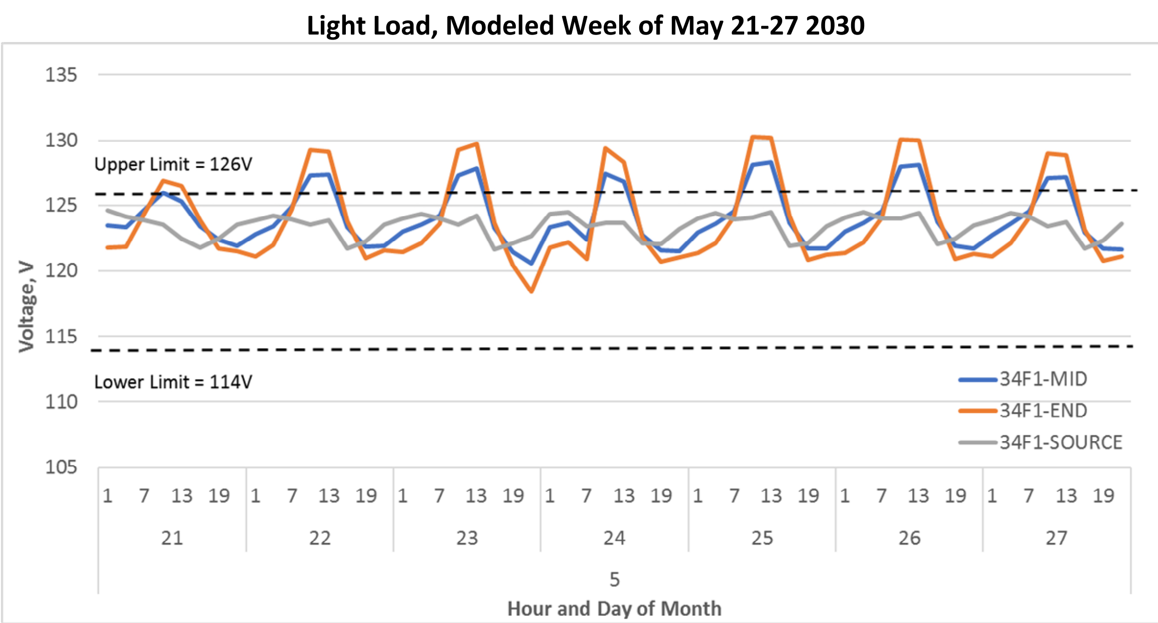


Figure 5.2: Example Overvoltage and Under-Voltage Risks
(Feeder – 34F1; Forecast Year – 2030; Scenario – High DER; Voltage basis – 120V nominal, ANSI normal +/- 5% = 126V upper limit, 114 V lower limit)

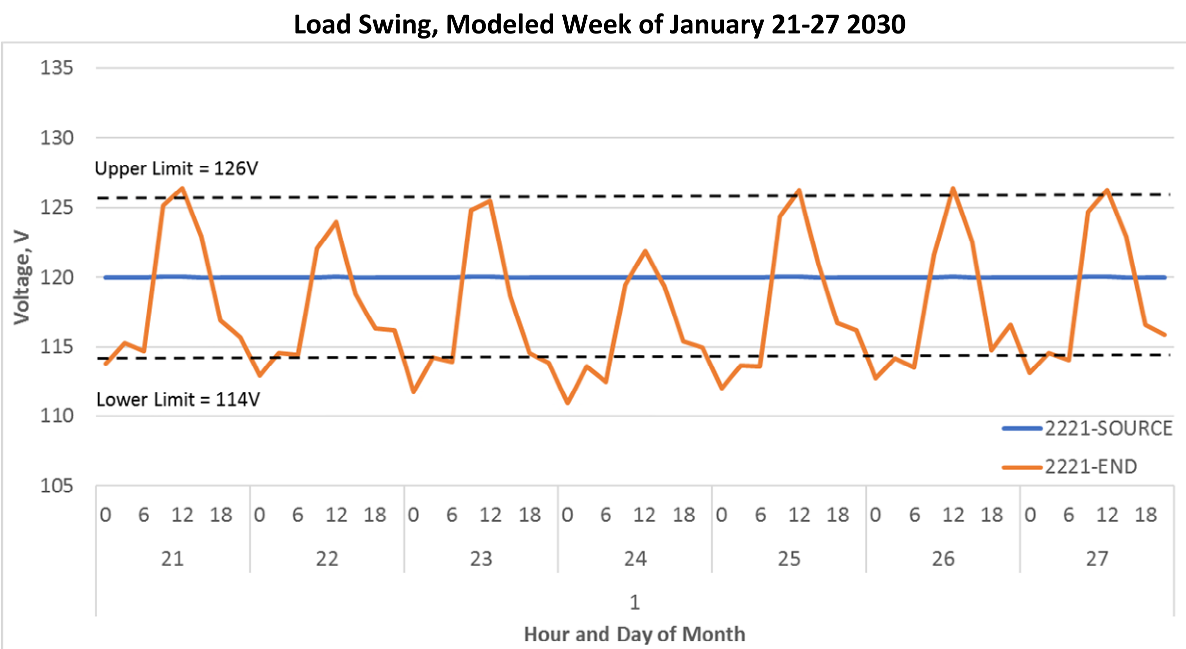


Figure 5.3: Example Sub-Transmission Overvoltage and Under-Voltage Risks Within Same Day
(Line – 2221; Forecast Year – 2030; Scenario – High DER; Voltage basis – 120V nominal, ANSI normal +/- 5% = 126V upper limit, 114 V lower limit)

To alleviate these issues, the proposed Advanced Capacitors & Regulators would adjust system voltages up and down in a dynamic manner to accommodate the variable output of DER technologies. For example, as solar DG output increases system voltage, capacitors would switch off and regulators would adjust tap positions to accommodate the voltage change within the acceptable range. As solar DG output decreases and residential EV charging increases in the evening, the capacitors would switch back on and the regulators would readjust to address the voltage drop.

Goals and Objectives

The Company plans to upgrade capacitor and regulator controls and install Sensors to sufficiently meet ANSI voltage standards even under high levels of intermittent renewable DG and two-way power flows. Centralized processing and control of these devices will be incorporated into the Company's ADMS to maximize benefits from the advanced capacitor and regulator functionalities. The Company has developed a minimalist approach to near-term capacitor replacement focusing on existing capacitor and regulator units and a small number of new units. The Company is also considering future technology in its deployment plans with scaling possibilities. For example, faster response times and more granular voltage control may be necessary as DER accumulates on the system and the voltage issues compound. Certain

DERs with advanced controls from power electronic devices (e.g., smart inverters) and a communication path to the utility could be used to mitigate their own voltage impacts as well as support the system's voltage needs. The projected deployment of Advanced Capacitors & Regulators allows for the DER technology, including contractual and communication details, to be developed in parallel. The Company will continue to monitor and encourage the development and deployment of power electronic based devices such as smart inverters, static-var compensators and other developing technologies; and scale the proposed capacitor and regulator deployment down, if necessary, at the appropriate time.

Beyond compliance with existing voltage regulation standards, the Company plans to continue to seek opportunities to gain system efficiencies and customer energy savings through VVO/CVR where it is cost beneficial to do so. The advanced controllers the Company is proposing to utilize on all new capacitors and regulators can integrate within a VVO scheme and will facilitate the deployment of VVO/CVR on all targeted feeders. Where advanced controllers already exist on a feeder, the marginal cost to deploy VVO/CVR includes the integration costs of the centralized VVO controller and optimization engine and any additional remote-end Sensors at select locations on the feeder. Looking towards the future, the Company is investigating how customer owned devices (e.g., smart inverters, AMF meters) may be able to be integrated to assist or improve efficiency even further. In addition, a DERMS is anticipated in the later-part of the 5-year Plan to enable DER integration in voltage management to address local grid constraints. Details are provided in *Section 14: Distributed Energy Resource Management System (DERMS).*

Benefits

Advanced Capacitors & Regulators, along with ADMS-based voltage control and a VVO/CVR platform, provide Power Quality Management functionality and support or enhance a number of other key functionalities, including Observability (Monitoring and Sensing), Distribution Grid Control, Grid Optimization, and DER Operational Control.[7] Power Quality Management functionality results in two quantified benefit impacts summarized below.

- Reduced Customer Energy Use and System Capacity Requirements (when coupled with Sensors, VVO/CVR platform, and other supporting solutions) by enabling the system operator to manage voltage impacts of renewable DERs and operate distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption and peak demand from customer appliances

- Avoided D-System Infrastructure Cost (when coupled with Advanced Reclosers & Breakers, ADMS, VVO/CVR platform, and other supporting solutions) due to the ability of the system operator to autonomously or remotely control power flows on the distribution system, by maintaining voltage compliance across all times of a year and across the distribution system with various levels of DER penetration, rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption

Voltage compliance is a fundamental utility requirement for safe and reliable electric service. The Plan allows this fundamental requirement to be integrated over time to maximize net benefits, including customer energy savings, and realize new functionalities where and when they are needed. Without the ability to manage voltage more granularly, interconnection studies would impose substantial limitations on the pending DER, including for example, requiring expensive system upgrades or reducing the size of the DER that can be interconnected, which could make many DER projects uneconomic.

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

The scale and timing of the deployment of Advanced Capacitors & Regulators will be driven by needs identified through distribution planning studies and DER interconnection studies. The near-term deployment of these devices will be targeted to those areas and feeders with existing DER penetration and the greatest voltage compliance risk. Analysis has shown that the greatest compliance risk is on relatively long radial feeders supplied by the subtransmission system,[13] especially 15kV substations and feeders. As shown in the hosting capacity map in Figure 5.4, these feeders are predominantly located in the western part of the state, but they are becoming more prevalent in other areas as well. Focusing on the feeder-level hosting capacity, particularly for subtransmission sourced feeders, and observing DER pending applications will inform the long-term deployment scope and schedule.

[13] In Rhode Island, the subtransmission system includes distribution circuits typically between 15kV class and 35kV class, which can supply other distribution substations, large DG, or customers with high electric loads

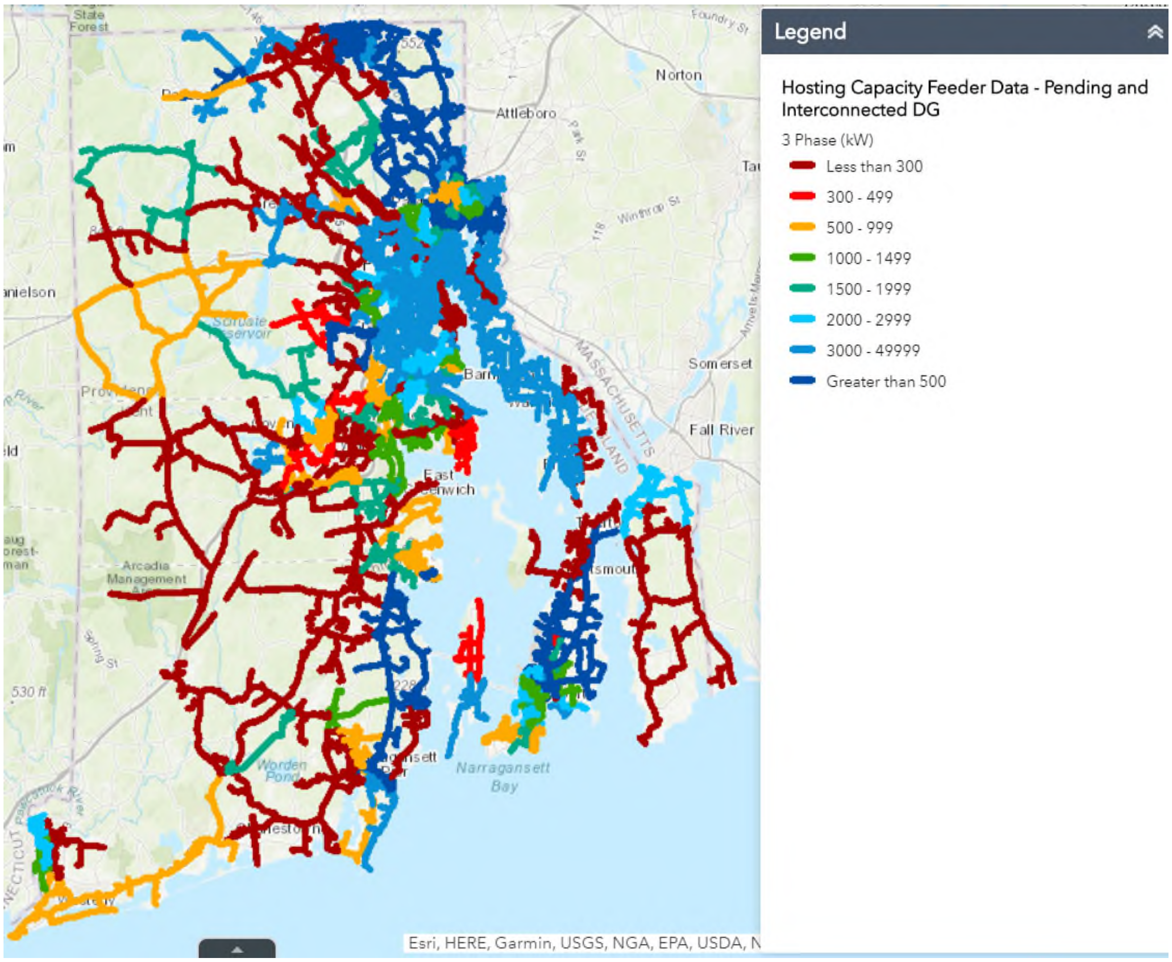


Figure 5.4: Rhode Island System Data Portal Hosting Capacity Map
(red hosting capacity means limited DER interconnection potential)

In considering the system needs through 2030, the Company assessed multiple scenarios with varying levels of DER penetration including DG and electrification of transportation and heating sectors. This assessment resulted in a range of possible DER deployment volumes over the period. While actual deployments in each annual ISR Plan submittal will be determined based on the current and near-term need, the results of the GMP assessment expects deployment to fall between the Low and High DER scenarios. Details for each scenario are presented in *Section 3.2: Future State Scenarios* of the GMP Business Case. The range of expected Advanced Field Devices and supporting system deployments needed to effectively manage voltage in the future is presented below for the Low DER and High DER scenarios.

Low DER Scenario

The Low DER Scenario would upgrade feeders served by approximately five substations per year. This is roughly equivalent to 20 feeders per year. The effort would focus first on subtransmission sourced feeders (25-30% of the system) with high DER penetration, and then 15 kV transmission sourced feeders (30-35% of the system) with high DER penetration. These annual investments are assumed to start in FY 2023 and continue through FY 2031. FY 2022 investments are assumed to be a more moderate deployment of two substations and 12 feeders through the Company's VVO/CVR Pilot program. Total deployment from FY 2022-2031 is estimated to reach 47 substations and roughly 192 feeders (approximately 50% of the system).

- Voltage Compliance Investments FY 2023-2031
    - Sensors – 20 devices per year (see *Section 4: Feeder Monitoring Sensors*)
    - Advanced (Distribution) Capacitors – 50 devices per year
    - Advanced (Station) Regulators – 60 devices per year
    - ADMS – enabled by FY 2024 (see *Section 8: Advanced Distribution Management System*)
    - DERMS – enabled by FY 2027 (see *Section 14: Distributed Energy Resource Management System*)

- Voltage Optimization Investments FY 2023-31
    - Additional Sensors – 40 devices per year in the Grid Mod Only Case (see *Section 4: Feeder Monitoring Sensors*)[14]
    - VVO Central Control – up to 5 substations per year (see *Section 12: Volt-Var Optimization/Conservation Voltage Reduction*)

High DER Scenario

The High DER Scenario would upgrade feeders served by approximately nine substations per year or approximately 36 feeders per year. The effort would focus first on 15kV subtransmission sourced feeders (25-30% of the system) with high DER penetration, and then 15 kV transmission sourced feeders (30-35% of the system) with high DER penetration, and finally, the rest of the feeders from all remaining substations (35-45% of the system). These annual investments are assumed to start in FY 2023 and continue through FY 2031. FY 2022 investments are assumed to be a more moderate deployment of two substations and 12 feeders through the Company's VVO/CVR Pilot program. Total deployment from FY 2022-2031 is estimated to reach 83 substations and roughly 336 feeders (approximately 90% of the system).

[14] Following the deployment of AMF under the Full Grid Mod Case, it is anticipated that the use of secondary metering will eliminate the need for the additional feeder monitoring sensors. This will be evaluated and verified during the detailed design associated with the implementation of ADMS and the capabilities of the selected AMF vendor.

- Voltage Compliance Investments FY 2023-2031
  - Sensors – 36 devices per year (see *Section 4: Feeder Monitoring Sensors*)
  - Advanced (Distribution) Capacitors – 90 devices per year
  - Advanced (Station) Regulators – 108 devices per year
  - ADMS – enabled by FY 2024 (see *Section 8: Advanced Distribution Management System*)
  - DERMS – enabled by FY 2027 (see *Section 14: Distributed Energy Resource Management System*)

- Voltage Optimization Investments FY 2023-2031
  - Additional Sensors – 72 devices per year in Grid Mod Only Case (see *Section 4: Feeder Monitoring Sensors*)
  - VVO Central Control – up to 9 substations per year (see *Section 12: Volt-Var Optimization/Conservation Voltage Reduction*)

Status

The Company does not have any active programs to install Advanced Capacitors & Regulators specifically targeting areas with significant levels of DER penetration, where these capabilities can be leveraged to support the efficient operation of a distribution system with high amounts of DER. However, the Company has deployed 122 advanced capacitors and 52 advanced regulators on 19 feeders from 6 substations in Rhode Island as part of the Company's VVO/CVR Pilot program. Deployment on an additional 14 feeders is anticipated through the Company's VVO/CVR program in the FY21 ISR Plan.

Major Tasks

The locations and specifications of field devices will first be proposed, scoped, and sanctioned based on area studies and cost-benefit estimates using Company forecasts and feeder-level information, including expected future DER interconnections, VVO/CVR energy savings, and other customer benefits. Next, long lead-time equipment orders will be placed and the Company will work with equipment vendors to configure the field devices according to the specified requirements. Project Plans will include procurement, office testing, constructability reviews, training, installation, programming, field testing, and M&V of the full system.

Cost Estimate

Table 5.1 presents the 5-year cost estimates for the Advanced Capacitor & Regulator investment under the High and Low DER customer adoption scenarios. The Company estimates investing between $24 and $41 million through FY26, depending on customer DER adoption. The costs estimates shown include CAPEX, OPEX, and RTB costs including Telecoms RTB, which accounts for the cost of third-party cellular fees necessary to communicate with the device's radio.[15]

Table 5.1: Advanced Capacitors & Regulators Cost Estimates – 5-Year Plan

Advanced Capacitors & Regulators, $ million ($2020)	Yr 1 FY 2022	Yr 2 FY 2023	Yr 3 FY 2024	Yr 4 FY 2025	Yr 5 FY 2026	5-Yr Tot FY22-26
High DER Scenario						
Capacitors & Regulators CAPEX	$ 2.84	$ 8.51	$ 8.51	$ 8.51	$ 8.51	**$ 36.86**
Capacitors & Regulators OPEX	$ 0.27	$ 0.81	$ 0.81	$ 0.81	$ 0.81	**$ 3.51**
Capacitors & Regulators RTB	$ -	$ 0.02	$ 0.06	$ 0.09	$ 0.13	**$ 0.30**
Capacitors & Regulators Telecom RTB	$ -	$ 0.01	$ 0.05	$ 0.02	$ 0.02	**$ 0.10**
Total	**$ 3.11**	**$ 9.35**	**$ 9.42**	**$ 9.43**	**$ 9.46**	**$ 40.77**
Low DER Scenario						
Capacitors & Regulators CAPEX	$ 2.84	$ 4.73	$ 4.73	$ 4.73	$ 4.73	**$ 21.74**
Capacitors & Regulators OPEX	$ 0.27	$ 0.45	$ 0.45	$ 0.45	$ 0.45	**$ 2.07**
Capacitors & Regulators RTB	$ -	$ 0.02	$ 0.04	$ 0.06	$ 0.08	**$ 0.21**
Capacitors & Regulators Telecom RTB	$ -	$ 0.01	$ 0.03	$ 0.01	$ 0.01	**$ 0.07**
Total	**$ 3.11**	**$ 5.21**	**$ 5.25**	**$ 5.25**	**$ 5.27**	**$ 24.09**

The investment estimate above covers a broad range due to the uncertainty in the level of customer DER adoption and the resulting distribution system issues. Therefore, the Company will present the actual deployment plan and request for cost recovery through the Company's annual ISR Plan filings.

6. Advanced Reclosers & Breakers

Background

In addition to voltage management, the Company provides safe and reliable service by ensuring equipment is operated within its rated capacity and that faults on the system are cleared in a fashion that prevents damage to equipment and interrupts service to as few customers as possible. Increasing customer DER adoption adds complexity to managing distribution system loading and the protection systems.

[15] Telcom RTB costs are gradually reduced starting in FY25 as the OpTel Strategy investments enable the Company to operate a private cellular network.

The distribution system has traditionally been built to ensure adequate capacity is available at all times by building the necessary distribution system capacity to accommodate forecasted peak loading on extreme weather days in accordance with the Company's planning criteria.[16] By designing the system to meet these worst-case scenarios, day-to-day load management was not historically necessary for distribution grid management. However, the coincidence of DER injections with traditional load shapes is not well aligned, and DER can be located in less capable areas of the system resulting in possible overloads in the reverse direction under light load conditions.

The protection systems that detect and isolate sections of a feeder during fault conditions were also designed with one-way power flow assumptions. These protection systems rely on high levels of fault current to operate very quickly, generally in less than one second. The higher the fault current, the faster a protective device must operate to clear the fault and de-energize the faulted sections from any source that could contribute fault current into the fault. With DG, there are many more sources of fault current from parallel paths. Contributing fault current from multiple directions can desensitize the protection systems and result in slower operation and increased risk. Fault current levels and the clearing time of protection systems are the determining factors in the amount of damaging energy released during a fault or arc fault. Arc flash analysis is performed to evaluate the amount of available energy occurring during a fault and to determine appropriate work practices and personal protective equipment for worker safety.

In the very near future, as customers more actively manage their loads and as levels of DER injections increase, loading and system protection issues will need to be monitored and adjusted more frequently due to the more dynamic nature of a distribution system. Similar to voltage management, the increasing complexity of the grid will require a transition away from simple autonomous controls to control schemes that are integrated across an entire feeder. As the number of sources for fault current increases and becomes more dynamic due to the distributed and intermittent nature of DER, the protection schemes employed will need to become more dynamic and integrated as the contributions to fault current change across seasons, months, weeks, and days.

Legacy Technology

Reconfiguration of the distribution system to redistribute loads generally requires the dispatch of line crews to manually operate switches and other field devices. There is currently limited functionality to remotely or automatically rearrange the distribution system for loading issues in Rhode Island. Any system rearrangement to address forecasted loading concerns is planned well in advance and is typically associated with nearby construction needs to increase capacity.

[16] Planning criteria is described in the Company's Distribution Planning Guide available on the Rhode Island System Data Portal, http://ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/Distribution_Planning_Criteria.pdf

Crews are dispatched to recloser and switch locations to receive verbal communications from the Distribution Control Center.

The protection system consists of breakers, reclosers, and fuses. Protection devices operate automatically and are coordinated through device settings and standard fuse sizes under fault conditions. The settings and fuse sizes are selected based on predictable fault current contributions from the central power plants and planned transmission system configuration. As described above, the DER can change the formerly predictable values and there is currently no way to adjust the settings in a dynamic fashion. To change settings, a crew must be dispatched with the settings file to be downloaded into the control unit. Under high DER penetration scenarios requiring numerous settings changes, a crew dispatch method becomes costly and impractical. With high DER penetration, there will be a need to adjust settings more frequently and remotely.

Goals and Objectives

The Company plans to install new line reclosers with advanced controls (i.e., Advanced Reclosers), new feeder ties leveraging load break switches with advanced controls (i.e., Advanced Breakers), and targeted upgrades to existing line reclosers as necessary to foster coordinated response through the ADMS. The location and timing of these upgrades will be determined based on needs identified in planning studies and interconnection studies and included in the Company's annual ISR plan.

The scale of deployment of advanced controlled devices for switching and system protection were evaluated considering the same scenarios as was done for voltage management. The near-term deployment of line devices will be targeted to those areas and feeders with existing DER penetration and the greatest load and protection risk. Analysis has shown that the greatest voltage and protection compliance risk to be the distribution feeders sourced from the subtransmission system, predominantly 15kV feeders located in the western part of the state. In addition, these same feeders have the greatest load risk because they are located in the more rural portions of the state with available land for DER development. Subtransmission sourced systems also have higher source impedance than transmission sourced systems. In other words, they are electrically further away from the large transmission connected generation plants. As a result, DER can have a greater percentage impact on fault current levels and protection system when interconnected to subtransmission sourced feeders.

Optimization Opportunities

With the need for remote control capability described above, additional reclosers and breakers will be added to the distribution system. Additional reclosers will also provide more feeder segments, which will result in fewer customers experiencing sustained outages when a fault occurs. Having more segments also makes it faster to locate faults, which can reduce outage time for all customers, even those in the faulted segment. In addition, software with overlaying control scheme to coordinate multiple Advanced Reclosers & Breakers on a feeder to achieve fast, reliable, and safe fault location, isolation, and service restoration (FLISR) can be incorporated for additional customer benefits where it is cost beneficial to do so. Details are provided in *Section 13: Fault Location, Isolation and Service Restoration (FLISR).* In addition, a DERMS is anticipated in the later-part of the 5-year plan to enable DER integration in load management to address local grid constraints. Details are provided in *Section 14: Distributed Energy Resource Management System (DERMS).*

Benefits

Advanced Reclosers & Breakers, along with ADMS-based Protection and Arc Flash and FLISR, provide Distribution Grid Control and Reliability functionalities. Advanced Reclosers & Breakers also support or enhance a number of other key functionalities, including Observability (Monitoring and Sensing), Power Quality Management, Grid Optimization, and DER Operational Control.[7] Distribution Grid Control and Reliability functionalities result in the quantified benefit impacts summarized below.

- OPEX Labor Efficiency (when coupled with ADMS and other supporting solutions) due to the ability for the system operator to perform remote switching and reduce communications, step checks, and field crew labor costs that would otherwise be required in a manual switching exercise

- Avoided D-System Infrastructure Cost (when coupled with Advanced Capacitors & Regulators, ADMS, VVO/CVR platform, and other supporting solutions) due to the ability of the system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs, rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption

- Reduced Outage Restoration Time (when coupled with ADMS, FLISR, and other supporting solutions) by enabling the system operator and control system to quickly locate and isolate a fault and restore power rather than waiting for field crews to locate a fault and restore power. Benefits are based on the monetization of customer impacts as presented in the DOE ICE Calculator.[17]

[17] The Interruption Cost Estimate (ICE) Calculator is a tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements. Details are provided at: https://www.icecalculator.com/home.

- Reduced DG Curtailment (when coupled with ADMS, DERMS, and other supporting solutions) due to the ability of the system operator to optimize power output from renewable DG, by rearranging the distribution feeders and maximizing the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance

The recommended plan enables the Company to ensure loading levels and protection systems are sufficient across all times of a year and in all areas of the distribution system with various levels of customer DER adoption. Load and protection management are fundamental utility requirements for safe and reliable electric service. The GMP enables this fundamental requirement to be achieved by integrating technology to more granularly manage the grid rather than simply building additional T&D capacity that is under-utilized most hours of the year. Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

As described in *Section 5: Advanced Capacitors & Regulators*, the scale and timing of the deployment of Advanced Reclosers & Breakers will be driven by needs identified through distribution planning studies and DER interconnection studies. Initially focusing on the feeder-level hosting capacity, particularly for subtransmission sourced 15kV substations and feeders, and observing DER pending applications will inform the long-term deployment scope and schedule.

In considering the system needs through 2030, the Company assessed multiple scenarios with varying levels of DER penetration including DG and electrification of transportation and heating sectors. This assessment resulted in a range of possible deployment volumes over the period. While actual deployments in each annual ISR Plan submittal will be determined based on the current and near-term need, the results of the GMP assessment expects deployment to fall between the Low and High DER scenarios. Details for each scenario are presented in *Section 3.2: Future State Scenarios* of the GMP Business Case. The range of expected Advanced Reclosers & Breakers deployment needed to effectively manage advanced switching and system protection in the future is presented below for the Low DER and High DER scenarios.

Low DER Scenario

The Low DER scenario would upgrade feeders served by approximately five substations per year or approximately 20 feeders per year. The effort would focus first on subtransmission sourced feeders (25-30% of the system) with high DER penetration, and then 15 kV transmission sourced feeders (30-35% of the system) with high DER penetration. The annual investments are assumed to start in FY 2023 and continue through FY 2031. No investments are included for FY

2022 in the GMP, although some investments could be made as part of the Company's nondiscretionary spending if an immediate need arises. Total deployment from FY 2022-2031 is estimated to reach 45 substations and roughly 180 feeders (approximately 50% of the system).

- Reliability Compliance Investments FY 2023-2031
  - Advanced (Distribution) Reclosers & Breakers – 90 devices per year
  - ADMS – enabled by FY 2024 (see *Section 8: Advanced Distribution Management System*)
  - DERMS – enabled by FY 2027 (see *Section 14: Distributed Energy Resource Management System*); DERMS investment could potentially be delayed under the Low DER Scenario

- Reliability Optimization Investments FY 2026-2031
  - FLISR Central Control – up to 5 substations per year starting in FY 2026 (see *Section 13: Fault Location, Isolation and Service Restoration)*

High DER Scenario

The High DER Scenario would upgrade feeders served by approximately nine substations per year or approximately 36 feeders per year. The effort would focus first on 15kV subtransmission sourced feeders (25-30% of the system) with high DER penetration, and then 15 kV transmission sourced feeders (30-35% of the system) with high DER penetration, and finally, the rest of the feeders from all remaining substations (35-45% of the system). These annual investments are assumed to start in FY23 and continue through FY31. No investments are included for FY22 in the GMP, although some investments could be made through nondiscretionary spending if an immediate need arises. Total deployment from FY 2022-2031 is estimated to reach 81 substations and roughly 324 feeders (approximately 90% of the system).

- Reliability Compliance Investments FY 2023-2031
  - Advanced (Distribution) Reclosers & Breakers – 126 devices per year
  - ADMS – enabled by FY 2024 (see *Section 8: Advanced Distribution Management System*)
  - DERMS – enabled by FY 2027 (see *Section 14: Distributed Energy Resource Management System*)

- Optimization Investments FY 2026-2031
  - FLISR Central Control – up to 9 substations per year starting in FY 2026 (see *Section 13: Fault Location, Isolation and Service Restoration*)

Both scenarios would also leverage and utilize the voltage compliance Sensors described in *Section 4: Feeder Monitoring Sensors*.

Status

The Company does not have any active programs to install Advanced Reclosers & Breakers targeting areas with significant levels of DER penetration, where these capabilities can be leveraged to support the efficient operation of a distribution system with high amounts of DER.[18] However, the Company has deployed 453 advanced reclosers on over 200 feeders in Rhode Island as part of customer requests for DER interconnections (22 midline reclosers and 66 PCC reclosers)[19] and Recloser Replacement programs targeting safety/reliability, damage/failure, and asset replacement (365 midline reclosers). The Recloser Replacement Programs target specific recloser populations that have known asset condition concerns, with the primary goal of ensuring that the existing reclosers continue to operate safely and reliably, as intended. While the asset condition-driven recloser replacements have benefits in common with the proposed GMP installations, the number and locations the installations differ from the GMP.

Major Tasks

The locations and specifications of field devices will first be proposed, scoped, and sanctioned based on area studies and cost-benefit estimates using Company forecasts and feeder-level information, including expected future DER interconnections, reliability improvements, and other customer benefits. Next, long lead-time equipment orders will be placed and the Company will work with equipment vendors to configure the field devices according to the specified requirements. Project plans will be developed and coordinated by our Grid Modernization Execution team with various internal groups, including Distribution Planning & Asset Management, Design, Material Planning, Resource Coordination, Control Center, Protection & Telecommunications Operations, Overhead Operations, Distribution Control & Integration, CNI, and Resource Planning groups. Plans will include procurement, office testing, FLISR validation, constructability reviews, training, installation, programming, field testing, and M&V of the full system.

Cost Estimate

Table 6.1 presents the 5-year cost estimates for the Advanced Reclosers & Breakers investment under the High and Low DER customer adoption scenarios. The Company estimates investing between $23 and $40 million through FY 2026, depending on customer DER adoption. The costs estimates shown include CAPEX, OPEX, and RTB costs including Telecoms RTB, which

[18] Note that the Company proposed DER Enabling Investments as part of the FY 2021 ISR, which consisted of the deployment of Sensors, Advanced Capacitors & Regulators, and Advanced Reclosers & Breakers to address the accumulation of DER on three feeders. This proposal was only approved for nondiscretionary spending pending a more holistic view of the costs and benefits of these investments in this GMP.
[19] Point of common coupling or "PCC" means the point where the generating facility's local electric power system connects to the utility's electric system

accounts for the cost of third-party cellular fees necessary to communicate with the device's radio.[20]

Table 6.1: Advanced Reclosers & Breakers Cost Estimates – 5-Year Plan

Advanced Reclosers & Breakers, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
High DER Scenario						
Reclosers & Breakers CAPEX	$ 1.43	$ 8.62	$ 8.62	$ 8.62	$ 8.62	**$ 35.91**
Reclosers & Breakers OPEX	$ 0.14	$ 0.82	$ 0.82	$ 0.82	$ 0.82	**$ 3.42**
Reclosers & Breakers RTB	$ -	$ 0.01	$ 0.06	$ 0.10	$ 0.15	**$ 0.32**
Reclosers & Breakers Telecom RTB	$ -	$ 0.00	$ 0.03	$ 0.01	$ 0.01	**$ 0.05**
Total	**$ 1.57**	**$ 9.45**	**$ 9.52**	**$ 9.56**	**$ 9.60**	**$ 39.70**
Low DER Scenario						
Reclosers & Breakers CAPEX	$ 1.43	$ 4.79	$ 4.79	$ 4.79	$ 4.79	**$ 20.59**
Reclosers & Breakers OPEX	$ 0.14	$ 0.46	$ 0.46	$ 0.46	$ 0.46	**$ 1.96**
Reclosers & Breakers RTB	$ -	$ 0.01	$ 0.03	$ 0.06	$ 0.08	**$ 0.18**
Reclosers & Breakers Telecom RTB	$ -	$ 0.00	$ 0.02	$ 0.01	$ 0.01	**$ 0.03**
Total	**$ 1.57**	**$ 5.26**	**$ 5.29**	**$ 5.31**	**$ 5.33**	**$ 22.77**

The investment estimate above covers a broad range due to the uncertainty in the level of customer DER adoption and the resulting distribution system issues. Therefore, the Company will present the actual deployment plan and request for cost recovery through the Company's annual ISR Plan filings.

7. Geographic Information Systems (GIS) Data Enhancements

Background

Geographic Information System (GIS) is a geographic-based technology that combines the power of maps with the function of a database. As grid operations increasingly require granularity, accuracy, and timeliness of data to achieve the benefits associated with advanced systems functionality, GIS will be the foundation on which many of these systems are built. The Company utilizes GIS as its authoritative source for distribution asset information and network configuration (i.e., "connected model"). GIS information is utilized in several business processes including distribution system project design, load flow modeling, outage management,

[20] Telcom RTB costs are gradually reduced starting in FY25 as the OpTel Strategy investments enable the Company to operate a private cellular network.

and analysis models. While the existing GIS and data sets maintained by the Company have been fit-for-purpose to date, the introduction of new uses for GIS integration, such as for ADMS applications and hosting capacity analysis, requires change. Without addressing the data as well as system performance and functionality requirements, the Company cannot take full advantage of the benefits that ADMS and advanced analytics platforms offer.

Industry experience has shown that investment in data enhancement is a critical enabler for the efficient use of advanced grid modernization applications. The importance of a GIS integration with ADMS was confirmed through an internal ADMS assessment the Company's New York affiliate conducted on 15 feeders. The assessment clearly demonstrated that enhanced GIS data is necessary for successful network modelling. Reinforcing this perspective is the US Department of Energy's, Insights into Advanced Distribution Management Systems publication which notes that: "[t]he foundation of an ADMS is the data. The ADMS is a control hub, and it must have accurate data to correctly model your system. Data collection and maintenance in your GIS is critical to your ADMS implementation, and business processes to maintain clean data is just as important."[21]

Lessons learned from these industry and company efforts have informed the Company's GIS implementation plans.

Goals and Objectives

Two types of Company resources and investments are required for successful completion of this project: Business Resources and Information Technology (IT) Resources. GIS Business Resources include investments and Company business resources necessary to analyze, identify, enhance, and populate the new or updated data for Rhode Island. This work is focused on activities to prepare the Company's distribution system data to support the increasingly granular data requirements of the advanced capabilities of ADMS and system planning. The work incorporates three primary activities: 1) analyze and enhance existing data including network connectivity, configuration, and attribute-level values; 2) identify and populate additional attributes and new asset types through field photo acquisition and other available data sources (e.g., field survey); and 3) identify and implement changes to enhance processes, quality control, and data governance.

GIS IT Resources include IT resources and investments necessary to configure, develop, and improve the GIS solution. This work is also focused on activities to support ADMS and system planning needs and is complementary to the GIS Business Resources work. Specifically, the work addresses three key areas: 1) configure and program GIS to accommodate new asset types,

[21] U.S. Department of Energy, *Insights into Advanced Distribution Management Systems*, 22 (February 2015), https://www.energy.gov/sites/prod/files/2015/02/f19/Voices%20of%20Experience%20-%20Advanced%20Distribution%20Management%20Systems%20February%202015.pdf

equipment, and data attributes (i.e., data model changes); 2) develop additional tools and enhance existing toolsets used to manage data quality and processes in GIS; and 3) refresh technical elements necessary to maintain the platform performance.

Benefits

GIS provides Distribution System Representation (Network Models) functionality, which provides a topological model of the physical distribution system and customer and DER connectivity. This functionality is a foundational element and supports all other key functionalities described in *Section 5.1.4: Functionality and Benefit Impacts Assessment* of the GMP Business Case.[7] In addition, the Distribution System Representation (Network Models) functionality results in the quantified benefit impact summarized below.

- OPEX Labor Efficiency due to increased automation, reduction in model correction, and other work related to correctly, completely, and timely updating system data. Without this project, the Company estimates a need to increase its enduring labor spend to comply with emerging data needs and timelines. This significant labor increase would be required to create and maintain the various network models used for distribution system planning and operational models. This OPEX Labor Efficiency benefit is included in the GMP BCA as "avoided GIS network model labor" (see *Section 8.4.3: Benefit Estimation* in the GMP Business Case).

Implementing the GIS Data Enhancement project will enable network models to be developed consistently and efficiently for distribution system planning, hosting capacity analysis, and operations utilizing ADMS. By providing accurate data with the appropriate level of granularity, the maintenance of system models can be further automated and refreshed more frequently to provide more timely and accurate system assessments. These efforts are foundational to enable the desired granular management of the grid envisioned in this GMP.

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment.*

Schedule

In accordance with the 2018 ASA, the Company is progressing the GIS Data Enhancement project in two key phases as presented in Figure 7.2. The first phase is focused on creating detailed workplans, fully defining process and system improvement needs, staffing delivery teams, and piloting. The second phase is the execution phase focused on delivering all elements of the data, system, and process components of the project aligned with the Company's ADMS data requirements.

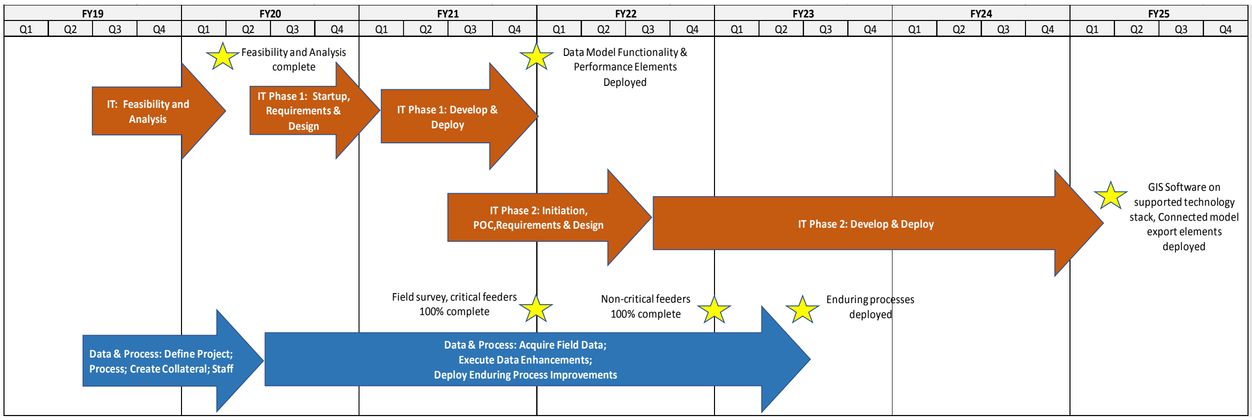


Figure 7.2: Rhode Island GIS Data Enhancement Deployment Timeline

Key areas of coordination for this project include:

- ADMS implementation schedule and execution across all Company jurisdictions with costs allocated as appropriate
- System Enhancements (IT Resources) work will be executed across all Company jurisdictions with costs allocated as appropriate

Status

GIS data improvements and data hardening are underway. This work includes field data verification, data validation, making required changes, and implementing a data quality monitoring process. In addition, changes to baseline GIS to allow for new asset types, new equipment, expanded attributes, and characteristics is also in progress. Going forward, GIS data cleanup and data model changes will continue and changes to GIS to support these requirements for ADMS will be progressed.

Work on the project began in 2019, and the project has achieved several milestones thus far, including:

- Onboarded a project manager and assigned support role amongst existing functional staff
- Developed and actively managing project plans, schedules, project tracking tools, and dashboards
- Initiated IT system upgrade project
- Defined processes and acquired field data on 378 feeders
- Procured contractors to execute data review and update data sets
- Created, piloted and refined project data workflows, processes, tools and training

- Developed and implemented GIS data health metrics to assess effectiveness of the project and to facilitate enduring data quality and governance
- Initiated work to address changing business process needed to facilitate modernization needs including ADMS
- Completed the initial review and remediation of system connectivity related errors

Major Tasks

Personnel with skills in engineering, operations, data management, and information systems have worked collectively to analyze data on the Company's entire distribution system consisting of over 420 distribution feeders encompassing more than 6,000 feeder miles. This team has developed a multifaceted approach that makes use of analytical models and techniques, Company and commercial data sources, and field observation. Using this information, the team will develop new GIS functionality as well as expand and improve the data necessary to maintain network models for advanced applications like ADMS. In addition, quality control processes and tools have been developed to monitor and continue to enhance data accuracy

System Enhancements (IT Resources)

- Configure and program GIS to accommodate new asset types and equipment, including adding expanded equipment attributes and characteristics; facilitate capture of greater data and modelling granularity for underground distribution networks; and facilitate more granularity for low-voltage secondary distribution networks
- Develop substation modelling capability to support operations and planning processes
- Develop additional tools and improve existing toolsets used to manage data quality and processes in GIS
- Configure, develop and deploy next generation, vendor supported GIS and associated modern hardware (Phase 2)
- Configure and deploy additional system tools to allow export of Asset and Connected model to a standard format widely consumable by third party analytics and other toolsets (Phase 2)

Data Enhancements (Business Resources)

- Analyze and enhance existing data, including network connectivity, configuration, and equipment attribute-level values
- Identify and populate new asset types, including network connectivity, configuration, and attribute-level values
- Ensure complete population of DER interconnections in GIS and populate relevant customer equipment attributes including nameplate, manufacturer, make, and model information

Process Review and Improvement (Business Resources)

- Review procedures and standards associated with the asset data life cycle
- Identify and implement changes to enhance processes, quality control, and reductions in cycle times
- Develop and implement data quality metrics and controls to facilitate continuous improvement

Cost Estimate

Table 7.1 presents the 5-year cost estimates for the GIS Data Enhancement investment. The Company estimates investing $4.64 million through FY 2026. These costs would be recovered through the Company's rate case filings. Note that the Company also performed planning work from FY 2019 through FY 2021 to ensure the Company is fully prepared to execute the projects. This work is being performed utilizing existing resources in the current MRP. An overview of the work completed to date is provided in *Section 4.1: 2017 Rate Case Funding for Grid Modernization* in the GMP Business Case.

Table 7.1: GIS Data Enhancement Cost Estimates – 5-Year Plan

GIS Data Enhancement, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
GIS IT Resources CAPEX	$ 0.60	$ 1.04	$ 0.92	$ 0.04	$ -	**$ 2.61**
GIS IT Resources OPEX	$ 0.30	$ 0.08	$ 0.09	$ 0.05	$ -	**$ 0.52**
GIS Business Resources OPEX	$ 0.24	$ 0.17	$ -	$ -	$ -	**$ 0.41**
GIS RTB	$ -	$ -	$ -	$ 0.55	$ 0.55	**$ 1.11**
Total	**$ 1.15**	**$ 1.29**	**$ 1.02**	**$ 0.64**	**$ 0.55**	**$ 4.64**

8. Advanced Distribution Management System (ADMS)

Background

ADMS includes Distribution Supervisory Control and Data Acquisition (DSCADA), Outage Management System (OMS), and Distribution Management System (DMS) advanced applications. They are intended to be implemented in an integrated fashion to enable the vision of a common network platform for operations. The advanced applications, as depicted in Figure 8.1, will enable Distribution Control Center operators to make more optimal system configuration decisions considering the actual constraints of the grid.

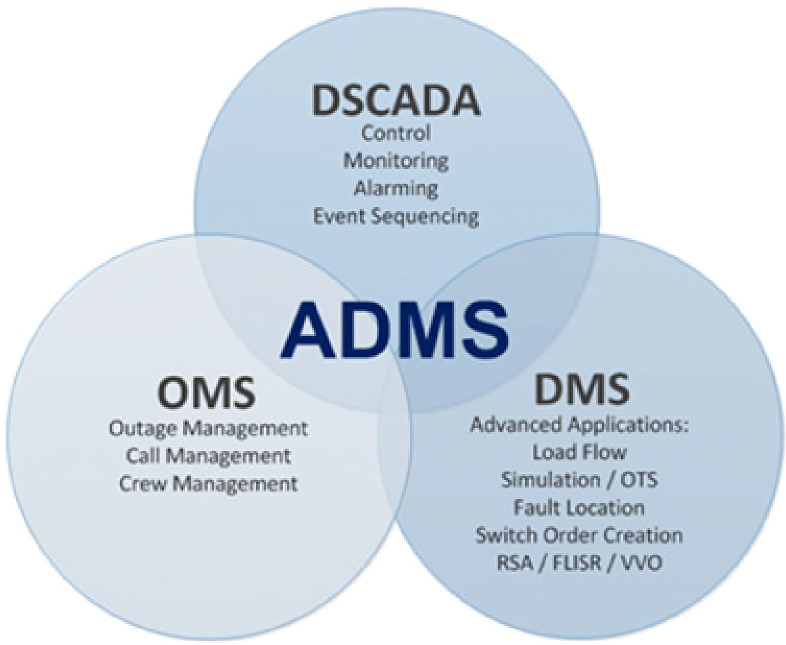


Figure 8.1: ADMS Key Components

The Company currently utilizes a stand-alone OMS for all of New England, which covers both Rhode Island and the Company's affiliate jurisdiction in Massachusetts. The existing computing hardware and software supporting the OMS was procured in 2009 and will be upgraded as part of the ADMS rollout. The Company also currently operates a Network Manager SCADA system that includes both T&D device data as well as Energy Management System (EMS) functionality utilized for transmission operations. A second similar distribution-specific SCADA (DSCADA) will be rolled out as part of ADMS. This will allow for the integration of the DSCADA equipment status and device data with OMS to improve outage analysis and improve solution accuracy and granularity with advanced applications.

Currently, operators rely on static system models and the distribution status information in SCADA (where available) to make operations decisions. For planned and emergency feeder reconfigurations, the operators utilize historic data, such as seasonal peak loading information, to help predict future conditions. Historically, system loading patterns have been somewhat predictable with regions, substations, and even individual feeders generally following similar trends. This is changing with the proliferation of DER and locational variability is increasing. Larger DER are monitored via pole top recloser installations at the point of common coupling (PCC). This allows operators to see the net loading and impact at those points, but when the grid is in an abnormal state, the voltage and loading impacts across the feeder are not well known.

In addition, any advanced automation schemes are currently built as stand-alone functions. The operators can monitor the actions of the programs via the SCADA system, but they run independently based on "as-designed" feeder configurations rather than adapting to the real-time "as-switched" feeder configuration.[22] This means that these automated schemes may be disabled for any configuration of the distribution grid out of its normal "as-designed" state.

Finally, over the last decade, the Company has deployed a growing number of field devices integrated with the existing SCADA system, such that the amount of data brought back from distributed devices has increased significantly. The rollout of Advanced Capacitors & Regulators for VVO/CVR, DER monitoring via PCC reclosers, and Sensors is creating much faster data growth on the distribution side than ever before. This proliferation of remote telemetered devices on the distribution system is already straining the capacity of the existing SCADA system. As noted above, the existing SCADA system includes both transmission and distribution (T&D) device data.

Goals and Objectives

The Company defines its ADMS investment as an integrated grouping of hardware and software necessary for Distribution Control Center operations to provide greater visibility, situation awareness, and optimization of the electric distribution grid as well as improved efficiencies through automating multiple control center processes. Benefits specific to the Distribution Control Center users include:

- Centralizes visualization, monitoring and control on a common network model with all device data, real time data, ratings and setting data, a "single pane of glass" to support increase efficiencies and ease of use for control center personnel when preparing planned and emergency switching plans
- Produces switching orders generated using load flow solutions, which reduces translation efforts
- Integrates real time outage notification status from telemetered equipment into the OMS, which reduces duplication of efforts in verifying outages and updating outage time after the event
- Expands situational awareness and visibility of future predicted states with respect to system operations through short term sub-regional, substation, and feeder level forecasts
- Maintains OMS reliability in support of Distribution Control Center and Storm Room operations

[22] "As-switched" refers to the network model the operators use (i.e., one line diagrams and geographic maps of the electric grid) that are updated to represent the current state of the grid such as what switches are open and closed on the distribution grid.

- Creates platform and network model to support interfacing DERMS and/or distribution market systems

ADMS is currently being progressed to continue safe and reliable operations under growing system complexities such as dynamic load profiles from increasing levels of customer DER adoption. The Company believes ADMS is a critical platform for the integration and operational management of DERs as their impact on grid performance grows. The ADMS will incorporate real-time data into useful solutions from an ever-growing number of Advanced Field Devices and DERs. ADMS will also incorporate AMF data as it becomes available. Examples of data utilized from AMF include power status notifications (e.g., power on / power off), voltage (e.g., high / low / partial power), and some demand data acquired by the system at a predetermined frequency.

ADMS will provide the Company's operators with foundational functionalities such as load flow analysis, restoration switching analysis, switch order creation, and state estimation that are not available to Distribution Control Center operators today. When planning to reconfigure the grid, ADMS will allow the operators to simulate the future state (i.e., reconfigured grid) to test the reconfiguration approach and ensue the most efficient switching that yields optimal power quality. DERs will be operationally integrated into the ADMS network model to allow operators to assess their effect on the grid, as well as leverage them for support where possible. In addition, ADMS will become the platform that coordinates multiple functions on a common "as-switched" network model. By incorporating control and automation capable grid devices (e.g., Advanced Capacitors & Regulators, VVO, and FLISR) with the centralized ADMS platform, these technologies can operate in abnormal grid configurations, further supporting operations and adding value. Finally, the deployment of a new DSCADA system will enable management of the proliferation of data from remote telemetered devices on the distribution system to ensure continued reliability.

Supporting Projects

Mobile Dispatch

Today dispatchers from the Distribution Control Centers and Storm Rooms utilize OMS to view customers calls and predicted outage locations. They prioritize "trouble calls" and outages and assign them to appropriate field crews based on capability and location as optimally as possible. ADMS-based Mobile Dispatch will interface with OMS and allow field crews with handheld devices to assign and dispatch themselves to outages based on their location, capabilities, and equipment. This can result in more efficient utilization of field crews and crew time and shorten "trouble calls" and outage response times. In addition, field crews will be able to update details concerning their time of arrival, incident details once on location, and estimated restoration times rather than calling that information into the centralized dispatch locations. In turn, the crews will receive near-real time updates directly on their devices to enable situational awareness in the field and reduce field-to-control center process steps increasing time spent on the task at hand. This project implements a limited rollout to select field personnel, with a view to explore options to improve the outage restoration process. Learnings will be applied towards developing the de-centralized process flows, and requirements for a full rollout. In summary, Mobile Dispatch is expected to improve restoration times, the efficiency and accuracy of restoration efforts, and worker safety.

RTU Separation

The ADMS project has interdependencies with other enabling efforts as shown in Figure 8.2 below. The main enabling projects for ADMS are the GIS Data Enhancements, RTU Separation, and Cyber Security projects. GIS Data Enhancements and Cyber Security projects are described in sections 6 and 9, respectively. The RTU Separation effort is most closely related to the ADMS project, so it is included here.

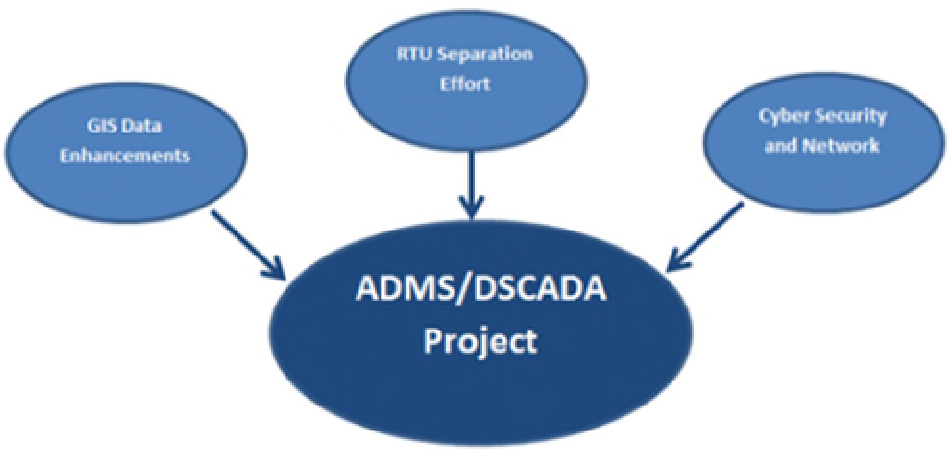


Figure 8.2: ADMS Interdependencies

A Remote Terminal Unit (RTU) is an interface device that collects information from smart devices in the field and packages it for transmission to the Company's SCADA system. The RTU Separation effort will facilitate the separation of transmission and distribution SCADA data by virtual (e.g., dual porting) and physical separation of the RTU and network allowing for integration with DSCADA and ADMS. This is necessary to make a clear divide for data and systems held to different security and compliance considerations. With the proposed separation of the SCADA system into a transmission-specific SCADA (TSCADA) and DSCADA, any RTU presently sharing T&D equipment data points will be reconfigured either virtually or physically to communicate with the appropriate SCADA. Specific RTU separation work includes the following:

- Develop and document requirements and design for separate transmission and distribution RTU data communications ensuring consistency with present cyber security and North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) compliance requirements
- Define the point of demarcation between transmission and distribution networks considering present operating process and future state of distribution operations
- Explore all options, including industry benchmarking, for RTU separation and assess pros and cons to each approach
- Assess where RTU separation work can be bundled with other active substation work to achieve delivery efficiencies
- Assess state of communications to determine if upgrade is needed to support increase in data
- Separate RTUs and data as required based on outcomes from above efforts:
    - Procure required hardware
    - Engineer new RTU configurations
    - Implement both virtual and physical separation of the RTUs and related data
- Commissioning of new RTUs and RTU configuration changes from present SCADA to DSCADA will be carried out once the DSCADA module is implemented under ADMS project

Distribution PI Historian

Plant Information (PI) Historian is a real-time data historian application with a highly efficient time-series database. This application can efficiently record data from process control systems (e.g., Distributed Control System, Programmable PLC) into a compressed time series database. Distribution system parameters are currently monitored by the existing SCADA system that feeds into PI Historian. The plan is to separate distribution data and setup a dedicated distribution-level PI Historian to interface with the distribution-specific SCADA (DSCADA) due to projected data growth from Advanced Field Devices and other grid modernization devices. PI Historian records hundreds of thousands of pieces of raw operational data generated via SCADA systems, with most of data being recorded every few seconds. Given the large number of intelligent electronic devices that will need to be monitored and controlled in an increasingly two-way power flow grid, the Historian's capacity and capabilities need to be expanded. The Company is developing plans to implement these upgrades as the Historian will be one of the main data sources feeding into various operational systems.

Protection & Arc Flash Application

Although the Company does not plan to invest in this application in the next three years, in the longer term, the Company expects there will be a clear need to invest in an ADMS-based Protection & Arc Flash application to maintain safe and reliable service with increasing levels of customer DER adoption. This application would automatically check if protective devices can clear all faults anywhere on the feeder. The goal is to make sure protection can clear faults when a feeder is in an abnormal state due to switching. In addition, the application will check the device pair coordination of all protective devices on a feeder based on protection settings and identify miscoordination. If there is a violation, it would check the alternate setting groups to see if another setting would provide coordination. This requires the relay and recloser settings to be defined in the ADMS database along with the alternate settings. The protection settings (e.g., fuse curves) would also be imported into the ADMS data.

Benefits

ADMS primarily provides Grid Optimization and Operational Analysis & Forecasting functionalities, but ADMS also supports or enhances a number of other key functionalities, including Observability (Monitoring and Sensing), Power Quality Management, Distribution Grid Control, Distribution System Representation (Network Models), Reliability, and DER Operational Control.[7] Grid Optimization functionality results in a number of quantified benefit impacts that are summarized below.

- Avoided Legacy OPEX Investments by avoiding the cost of a standalone OMS license in the future. Without investment in an integrated ADMS software package, which includes OMS functionality, the Company would need to continue to maintain its existing standalone OMS software license. This Avoided Legacy OPEX Investment benefit is included in the GMP BCA as "standalone OMS license savings" (see Section 8.4.3: Benefit Estimation in the GMP Business Case).

- OPEX Labor Efficiency (when coupled with Advanced Reclosers & Breakers and other supporting solutions) due to the ability for the system operator to perform remote switching and reduce communications, step checks, and field crew labor costs that would otherwise be required in a manual switching exercise

- Avoided D-System Infrastructure Cost (when coupled with Advanced Capacitors & Regulators, Advanced Reclosers & Breakers, VVO/CVR platform, and other supporting solutions) due to the ability of the system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs, rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption

- Reduced Outage Notification Time (when coupled with AMF) by integrating AMF-based autonomous outage notifications alerting the Company to trouble before receiving customer outage calls. Integrating this functionality with the Company's Outage Management System

(OMS) will reduce time from initial outage to Company notification, and enhance the Company's overall outage response capabilities.

- Reduced Outage Restoration Time (when coupled with Advanced Reclosers & Breakers, FLISR, and other supporting solutions) by enabling the system operator and control system to quickly locate and isolate a fault and restore power rather than waiting for field crews to locate a fault and restore power. Prior to the deployment of FLISR, ADMS will also enable the system operator to quickly generate efficient and optimal switch orders, which can help restore power faster. DMS applications will offer a suggested optimal restoration plan using load flow capabilities, taking into consideration DER and real time loading information, optimizing utilization of distribution assets and reducing waste. Benefits are based on the monetization of customer impacts as presented in the DOE ICE Calculator.[17]

- Reduced DG Curtailment (when coupled with Advanced Reclosers & Breakers, DERMS, and other supporting solutions) due to the ability of the system operator to optimize power output from renewable DG, by rearranging the distribution feeders and maximizing the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

There are many challenges associated with incorporating large amounts of real time data, complex network models, new operational processes, and a growing number of integrating systems. Therefore, the phased approach presented in Figure 8.3 will be implemented for the ADMS project to better manage these challenges by building on a solid foundational platform in Phase 1.

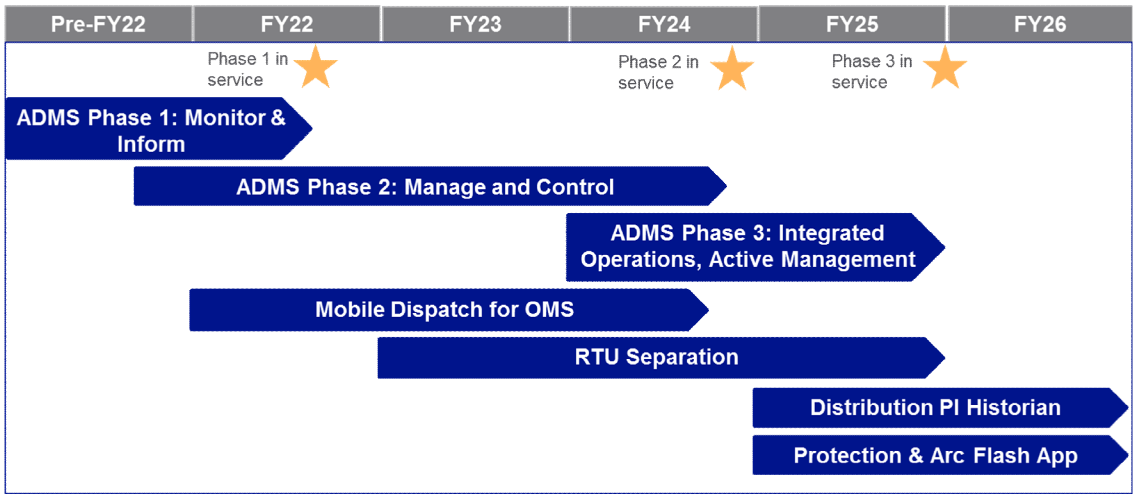


Figure 8.3: Rhode Island ADMS Deployment Timeline

This approach begins with the deployment of a foundational platform in Phase 1 on which future optimization applications can be integrated as illustrated in Figure 8.4. Benefits of a phased approach include:

- Allows for operations and support functions to become familiar with the use of baseline DMS applications in their daily work processes to improve operational efficiencies and awareness without disrupting critical processes
- Allows for the assessment of adoption of various functions and applications to help inform future phases and applications to maximize value add
- Phased approach is coordinated with GIS network model enhancement work to allow time for addition of all required elements and attributes to support advanced functionality as well as alignment with RTU separation work that supports the DSCADA

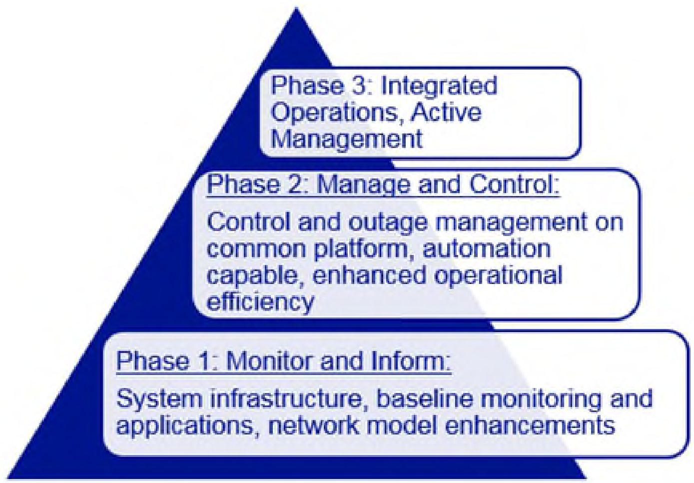


Figure 8.4: ADMS Deployment Phases

Status

The Company has completed an analysis and scoping effort for the development of the ADMS project. As part of this effort, business capabilities and system requirements have been captured. Phase 1 ADMS system design activities are complete, major vendor contracts are in place, and hardware and software have been procured. Infrastructure build out and system testing are in progress. A thorough analysis of operational procedures affected by the rollout of an ADMS as well as a review of change impacts and training requirements is completed. This will ensure the solution fits as designed into the Company's operations, is properly adopted, and delivers expected benefits. The project will be implemented utilizing a phased approach putting different modules and functionality into service over the next five years. This will maximize value add and benefits realization as early as possible as well as help to align ADMS with critical dependencies such as GIS and data model expansion and RTU separation.

The Company also performed detailed scoping and planning of the initial RTU separation work, including prioritization of the RTUs for dual porting based on both the complexity of the dual porting effort, the value to the substation and feeders for the future ADMS applications, and for alignment with existing substation work for increased work efficiencies. To date, the Company has completed RTU Separation for five substations, and initiated engineering and design for two of the three new RTU projects.

Major Tasks

The ADMS phased approach involves implementing DMS applications and an upgrade to the Company's existing OMS production system into one common platform and network model.

The project will implement a DSCADA by splitting the present SCADA system into separate TSCADA and DSCADA platforms. The resulting DSCADA system will be fully integrated with the DMS and OMS creating one common model-integrated ADMS.
The phases of the ADMS project are proposed as follows:

- Phase 1: Monitor and Inform (currently in the Build & Implement stage; planned in-service by June 2021)
    - Define requirements and design
    - ADMS system build and data population for required functionality
    - Test and verify DMS baseline applications functionality
    - Implementation of monitor and inform functionality via baseline DMS applications

- Phase 2: Manage and Control (planned in-service by December 2023)
    - Upgrade and refresh OMS incorporating functionality into common system and network model with DMS applications
    - Build DSCADA to support manage and control functionality for distribution devices
    - Interface sub-regional load forecasting
    - Initial testing and implementation of more advanced automation capable applications such as VVO/CVR and FLISR
    - ADMS components (i.e., DSCADA, OMS, DMS apps) available utilizing single platform

- Phase 3: Integrated Operations, Active Management (planned in-service by December 2025)
    - Fully integrated system automation centralizing VVO/CVR and FLISR applications
    - Move towards active network management leveraging distributed resources and interfacing system data allowing:
        - Real-time DER control guided by economic dispatch (when integrated with DERMS)
        - Automated system operations with minimal operator inputs
        - Publishing an "as-operated" system model to the Enterprise Integration Platform or future Data Lake to enable Advanced Analytics

<u>Cost Estimate</u>

Table 8.1 presents the 5-year cost estimates for the ADMS investment. The Company estimates investing $17.0 million through FY 2026. These costs would be recovered through the Company's rate case filings. Note that the Company also performed planning and development work from FY 2019 through FY 2021 to ensure the Company is fully prepared to execute the projects. This work is being performed utilizing existing resources in the current MRP. An overview of the work completed to date is provided in *Section 4.1: 2017 Rate Case Funding for Grid Modernization* in the GMP Business Case.

Table 8.1: ADMS Cost Estimates – 5-Year Plan

ADMS, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
ADMS Phase 1 and 2 CAPEX	$ 3.33	$ 2.30	$ 1.43	$ -	$ -	**$ 7.06**
ADMS Phase 1 and 2 OPEX	$ 0.88	$ 0.54	$ 0.30	$ -	$ -	**$ 1.72**
ADMS Phase 1 and 2 RTB	$ 0.30	$ 0.39	$ 0.39	$ 0.52	$ 0.63	**$ 2.23**
ADMS Phase 3 CAPEX	$ -	$ -	$ 0.67	$ 0.67	$ -	**$ 1.35**
ADMS Phase 3 OPEX	$ -	$ -	$ 0.13	$ 0.13	$ -	**$ 0.27**
Mobile Dispatch CAPEX	$ 0.10	$ 0.10	$ -	$ -	$ -	**$ 0.21**
Mobile Dispatch OPEX	$ 0.34	$ 0.34	$ -	$ -	$ -	**$ 0.68**
Mobile Dispatch RTB	$ 0.02	$ 0.03	$ 0.20	$ 0.20	$ 0.20	**$ 0.65**
RTU Separation CAPEX	$ 0.10	$ 0.26	$ 0.17	$ -	$ -	**$ 0.54**
RTU Separation OPEX	$ 0.07	$ 0.08	$ 0.05	$ -	$ -	**$ 0.19**
Distribution PI Historian CAPEX	$ -	$ -	$ -	$ 0.05	$ 0.05	**$ 0.09**
Distribution PI Historian OPEX	$ -	$ 0.41	$ 0.70	$ 0.14	$ -	**$ 1.25**
Distribution PI Historian RTB	$ -	$ 0.20	$ 0.34	$ 0.07	$ -	**$ 0.60**
Protection & Arc Flash App CAPEX	$ -	$ -	$ -	$ 0.01	$ 0.10	**$ 0.11**
Protection & Arc Flash App OPEX	$ -	$ -	$ -	$ 0.00	$ 0.02	**$ 0.02**
Protection & Arc Flash App RTB	$ -	$ -	$ -	$ -	$ 0.01	**$ 0.01**
Total	**$ 5.14**	**$ 4.66**	**$ 4.38**	**$ 1.79**	**$ 1.00**	**$ 16.98**

9. Underlying Information Technology (IT) Infrastructure

Background

Managing the distribution system more granularly in order to safely, reliably, and cost effectively meet customer's evolving expectations will depend on how well the Company can manage, analyze, and share underlying information or data. Managing high levels of DER integration while ensuring electrical network stability and performance will rely on deeper and faster insight into asset performance, operating conditions, and customer demand. As the Company deploys more Advanced Field Devices, advanced meters, and other technologies, there will be an enormous growth of incoming data. The investments in Underlying IT Infrastructure are necessary to fully unlock the value of advanced technologies and techniques like artificial intelligence or advanced analytics, which require that system and customer data is fit-for-purpose and readily available.

It is critical that accurate, timely, and consistent information flows seamlessly and continuously across boundaries. Current techniques for managing information is siloed and often manual. Deploying a "Data Management Platform" capability as illustrated in Figure 9.1 and moving toward an International Electrotechnical Commission Common Information Model (IEC CIM) to facilitate data sharing with external entities (e.g., PUC, DER aggregators, customers) are necessary to support evolving customer expectations including animating new distribution markets and engaging DER owners in the future.[23] Coordinated with business process changes, the proposed investment is focused on starting that journey - deploying a data catalog, modelling, and data quality toolsets to enable grid facing and asset management use cases. These capabilities will bring data consistency, data availability, and reduction of redundant or conflicting data.

[23] Appropriate security and privacy measures will be followed to ensure Critical Energy Infrastructure Information (CEII) and Personal Identifiable Information (PII) data is not shared.

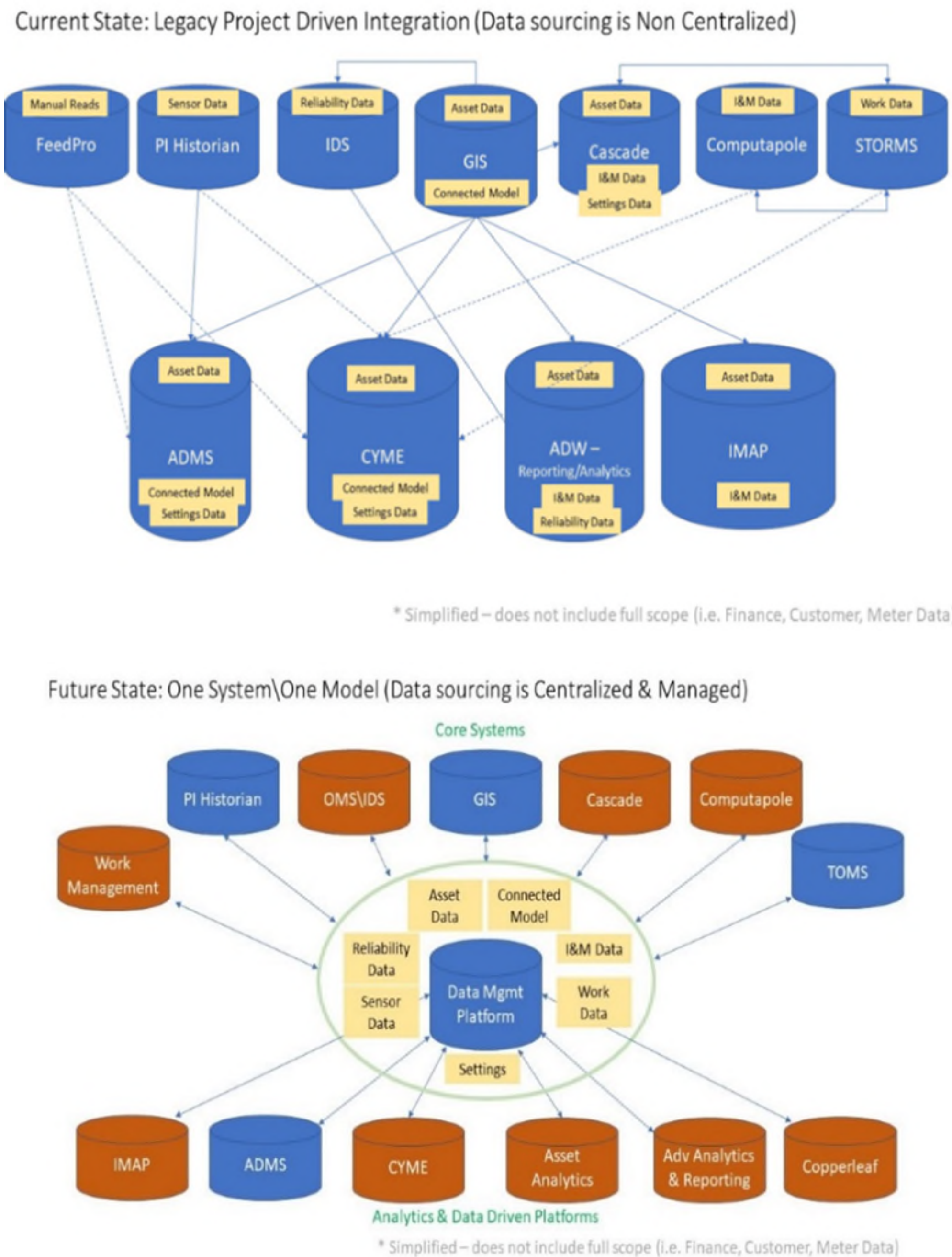


Figure 9.1: Current and Future State Data Platform

Future grid operations will also require comprehensive interaction between various systems and applications. This interaction is securely and reliably achieved through the implementation of an

Enterprise Integration Platform (referred to as Enterprise Service Bus in the 2017 Rate Case). Using a variety of integration patterns to cover diverse needs for security, volume (or throughput), speed (or latency), persistence (for auditing) and reliability, the Enterprise Integration Platform orchestrates complex operational processes across the system and application landscape. The Enterprise Integration Platform also provides the key function of periodically transporting data, securely, from source systems and applications to the Data Management Platform.

In addition, growing demand for raw operational data from SCADA by planning engineers and analysts negatively impacts the performance of the existing PI Historian database and servers that are critical for Distribution Control Center operations. In addition, NERC CIP restrictions on Critical Network Infrastructure (CNI)[24] access make PI Historian difficult to access from the Company's corporate network. The PI servers within the CNI environments are designed to support Distribution Control Center operations and not the bulk extracts being requested by users from the corporate network. To overcome these challenges, Corporate PI Historian investment will enable a dedicated instance of PI, that loads both T&D operational data to support planning uses and analysis requirements.

Goals and Objectives

The following Underlying IT Infrastructure investments are necessary to enable grid modernization functionalities and realize its full benefits.

Data Management

This investment will build foundational data management capabilities by enabling enhanced data governance across key datasets. This project will implement necessary data management tools and processes to ingest data, catalog data, and assess and improve data quality as illustrated in Figure 9.2. In line with the Company's Business Management System (BMS) standards, this centralized platform will be used to measure/monitor critical data elements and their accuracy, integrity, completeness, and consistency to support continuous data improvement. Setting this foundation is critical to establishing the longer-term vision of a data management platform, which will be necessary in the future as the amount of data collected and need for data continues to grow.

[24] CNI refers to tools and systems that are used to manage and control critical infrastructure.

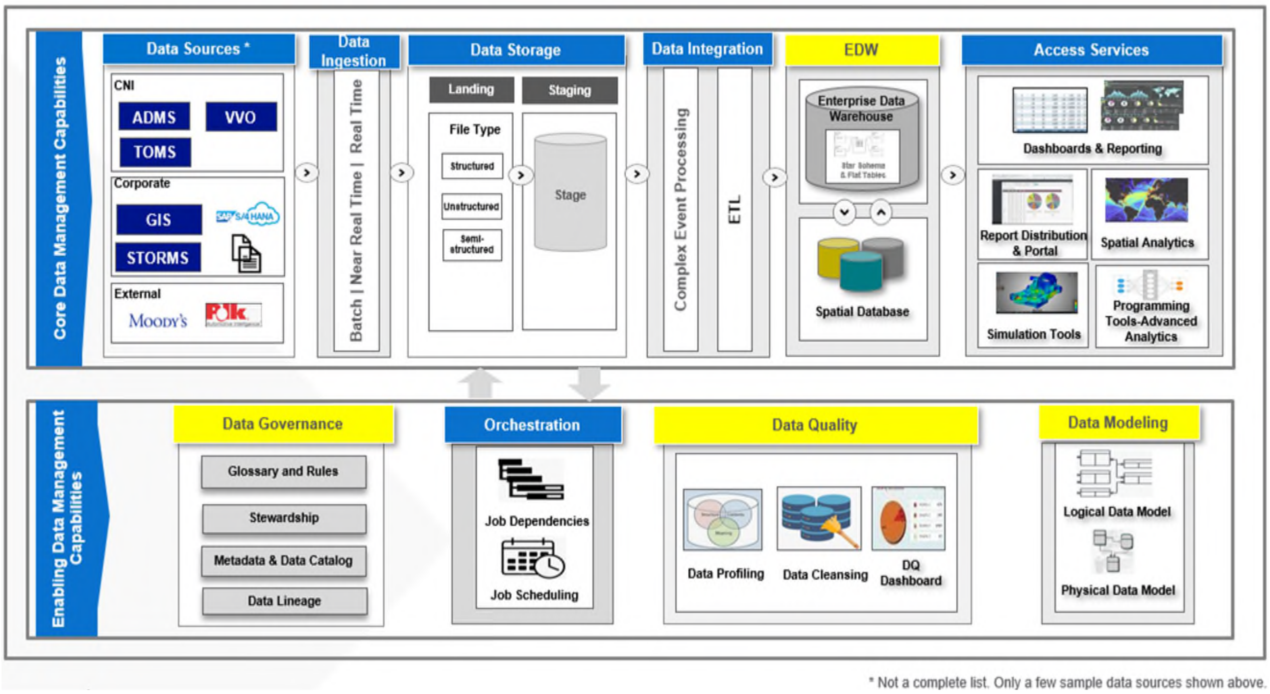


Figure 9.2: Grid Modernization Data Management Architecture

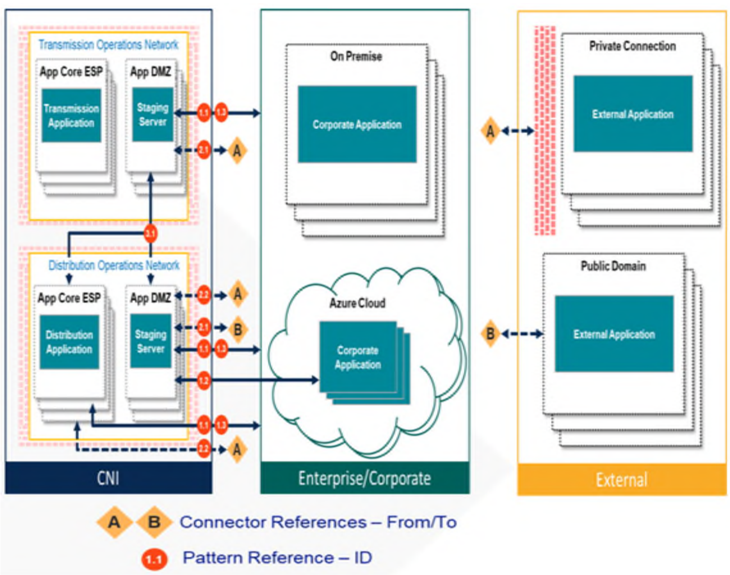
With a solid data management foundation, Data Lake and Advanced Data Analytics capabilities will deliver better quality data for analysis and decision-making. This includes data from GIS, ADMS, PI historians, DERMS, AMF, and field-edge devices and sensors. In the long-term, Data Management aims to achieve the following:

- Enhance operations and engineering decisions via network visibility of increasingly granular field-edge data points
- Support risk-based asset management decision making through improved data accuracy, confidence, and analysis[25]
- Support better predictive analytics and forecasting models for outage management, load flows, load forecasting and emerging distribution network functions
- Upgrade data management methodologies and capabilities
- Provide a central data platform of storage, integration, and access to distribution network and asset data

[25] Risk-based asset management takes into account the likelihoods and consequence of the failure of an asset.

Enterprise Integration Platform

Grid modernization applications will leverage the Enterprise Integration Platform to integrate various objects within and outside the Company and enable secure exchange of information between systems, services, and devices. This investment will provide all the necessary integrations between CNI applications such as ADMS, Telecommunications Operations Management System (TOMS), and VVO/CVR; corporate applications such as GIS; and external applications, which can be used for information on demographics for example. Integration patterns[26] include Real-time Integration Patterns using MuleSoft (e.g., on-premise[27] to/from CNI, external to/from CNI), and File Transfers (e.g., external to/from CNI, corporate to/from CNI, corporate to corporate). Figure 9.3 illustrates some of these integration patterns that form part of the Integration Platform Architecture.



CNI Integration Patterns			
ID	Category	Pattern ID	Pattern
1	CNI and Corporate	1.1	CNI and Corporate (Outsourced On-Prem)
		1.2	CNI and Corporate (Corporate Cloud)
		1.3	CNI and Corporate (Insourced On-Prem)
2	CNI and External	2.1	CNI and External (Public)
		2.2	CNI and External (Corporate)
3	Electric CNI and Electric CNI	3.1	Transmission ESP and Distribution ESP
		3.2	Distribution ESP and Distribution ESP
		3.3	Transmission ESP and Transmission ESP
4	CNI and Field End Points	4.1	Substation to CNI
		4.2	Field Devices to CNI

Figure 9.3: Grid Modernization Integration Platform Architecture (Illustrative)

Enterprise Integration Platform investment will equip the business with the latest, industry standard toolset for application integration. Integrations required for the entire grid modernization program are spread across multiple system-based initiatives including various Company applications (e.g., ADMS, GIS, TOMS, VVO/CVR, PI historians). Figure 9.4 summarizes the resulting capabilities and expected outcomes from this integration.

[26] Integration patterns are defined as combinations of security, volume (or throughput), speed (or latency), persistence (for auditing), reliability, and source and target applications.
[27] On-premise refers to applications deployed on the Company's data center, which includes compute, storage and networking devices.

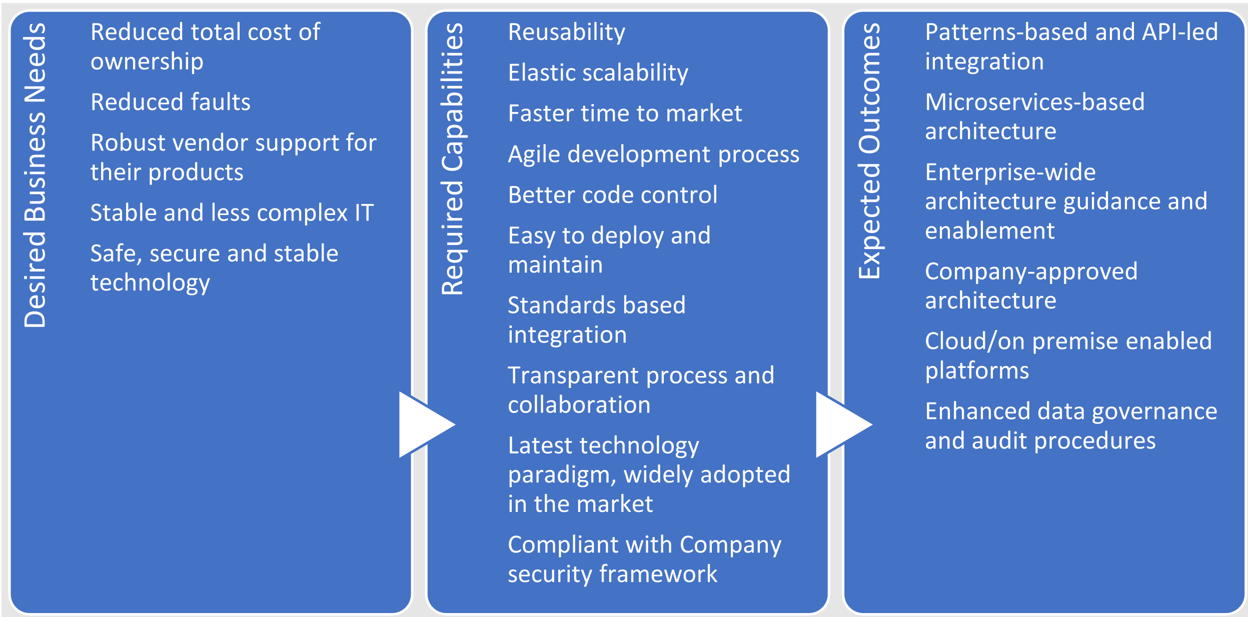


Figure 9.4: Needs, Capabilities, and Expected Outcomes for Enterprise Integration Platform[28]

By delivering core enabling integration infrastructure and services across the grid modernization investments, this project will provide the following benefits towards ongoing integrated, secure, scalable operation of business capabilities:

- Flexibility to integrate grid modernization applications with DER developer and even customer systems that leverage remote monitoring and control capabilities for improved reliability.

- Secure gateway for integrating external services rendered over Cloud or by third parties that are outside the National Grid network. Grid modernization relies on effective participation of third parties, including customers, for advanced use cases through integrated systems. The secure gateway ensures protection of IT assets both for the Company as well as its customers and other third parties using the Cloud.

- User productivity by leveraging and extending services utilizing the most appropriate protocol and integration standards (e.g. lightweight APIs for Mobile and Rich Web consumption). This improves the ability to handle the high-volume, low-latency requirements for integration between grid modernization applications.

[28] Microservices-based Architecture refers to a variant of the service-oriented architecture structural style, which arranges an application as a collection of loosely coupled services. In a microservices architecture, services are fine-grained and the protocols are lightweight.

- Provide end-to-end traceability and audit capability and alerting for operational efficiency, which helps improve reliability of operations

Examples of data exchanged across the various interfaces being built includes, but is not limited to: Customer Account Information, Network Model, Land Base, Load Forecasts, and Outages. Each of these data sets will be assessed for Critical Energy Infrastructure Information (CEII) and Personal Identifiable Information (PII) classification, and approved Data Protection measures will be included in the integration patterns.

Corporate PI Historian

The Corporate PI Historian investment will permit engineering, asset management, and advanced analytics teams secure access to this information without affecting performance of the operational systems. This project will implement a replicated reporting environment that can be queried on demand without impacting the performance of the CNI instance while honoring NERC CIP restrictions. The environment will be used to support internal modelling, analysis, and reporting needs. In addition, this project will allow the Company to consolidate data currently stored in separate systems and data stores, reducing complexity and enabling further analytical insights. Data will be migrated from two additional datasets/systems. These are:

- Feedpro – a system used to record and store device readings that are not RTU enabled and are collected manually
- Network Device Settings – Many assets on the Company's network have specific settings required for proper operation. This project will consolidate this information from several data sources allowing greater levels of data governance and furthering availability of this data to downstream systems and processes.

Benefits

Underlying IT Infrastructure provides Operational Information Management functionality, which provides highly reliable connectivity under both normal and degraded system operating conditions. This functionality is a foundational element and supports all other key functionalities described in *Section 5.1.4: Functionality and Benefit Impacts Assessment* of the GMP Business Case.[7]

Data Management, Enterprise Integration Platform, and Corporate PI Historian investments maximize the value that can be derived from key grid modernization investments, including Advanced Field Devices, GIS, ADMS, Operational Telecommunications, and Modular Optimizing Applications like VVO/CVR. These efforts are foundational to enable the desired granular management of the grid envisioned in this GMP.

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

There are many challenges associated with managing, analyzing, and sharing large amounts of real time data. Therefore, the phased approach presented in Figure 9.5 will be implemented for the Underlying IT Infrastructure project to better manage these challenges by building on a solid foundational platform in Phase 1. Benefits of a phased approach are summarized in *Section 9: Advanced Distribution Management System (ADMS).*

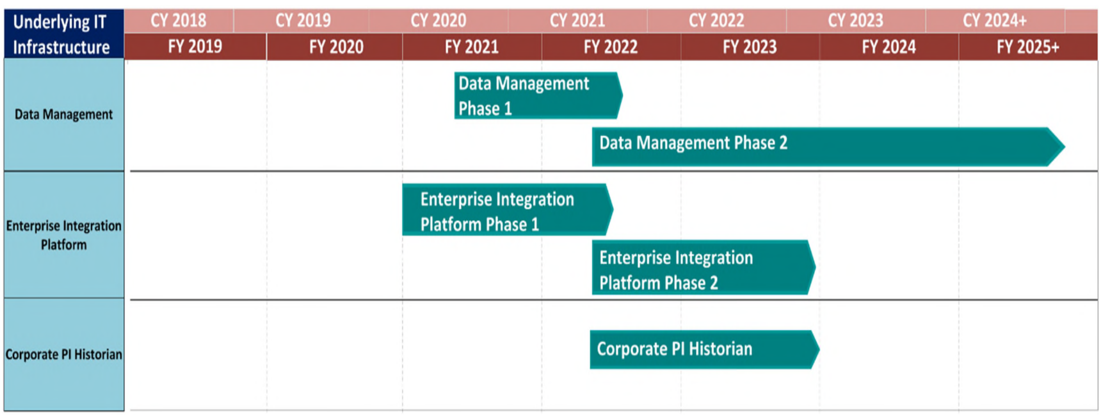


Figure 9.5: Rhode Island Underlying IT Infrastructure Timeline

Status

The Company has completed the business capability maturity assessment, applications mapping to capability model, and use case definitions to identify opportunities and dependencies. The program level conceptual solution has been established to address the needs of the Enterprise Integration Platform and Data Management. As part of these initial efforts, the Company completed an architecture assessment of the current integration tools in use, and their fitment for the grid modernization investments. In addition, the Enterprise Service Bus (part of Enterprise Integration Platform) has been selected and requirements, design and development efforts in progress are expected to complete in December 2021 and placed in-service. The Data Lake (part of Data Management) effort was initiated in Rate Year 2 and is expected to complete the initial platform in August 2021 and then be placed in-service. The Advanced Analytics effort (also part of Data Management) experienced alterations to the initial assumptions based on the planning and scoping for Enterprise Service Bus and Data Lake initiatives, but planning and scoping have been completed including requirements for Data Catalog and Data Quality, Business Capabilities, High Level Data Use Cases, and Preliminary Data Source identification.

Figure 9.5 below illustrates how the on-going investments in Underlying IT Infrastructure interact with each other and with other GMP investments.

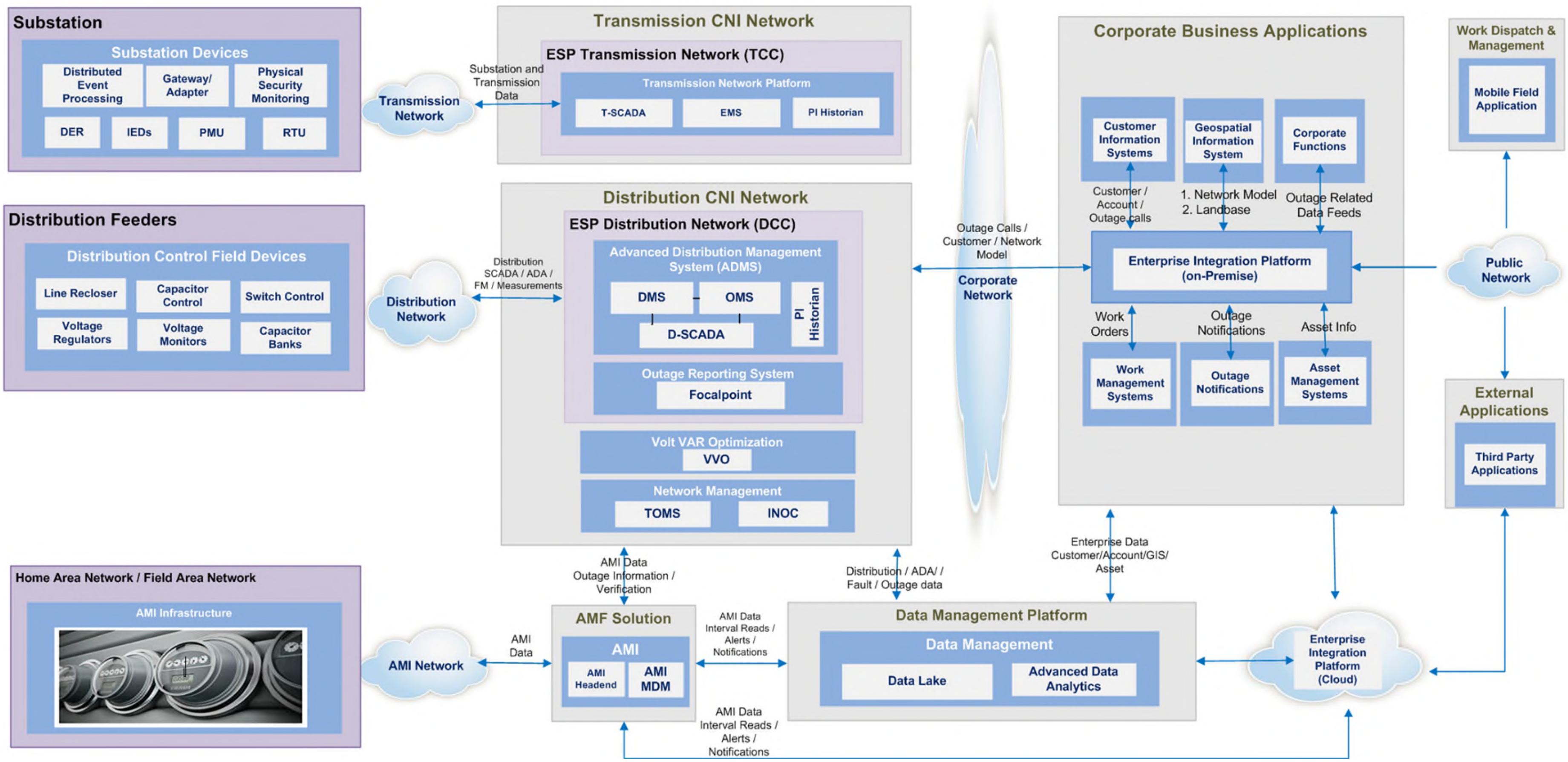


Figure 9.5: Grid Modernization IT Conceptual View

Major Tasks

Data Management

Phase 1 includes creating a comprehensive Data Model and setting up the tools and technologies for Data Quality and Data Cataloging capabilities. The project has already completed an assessment of Business Data Capabilities, High Level Use Cases, and a Preliminary Data Source Inventory. Following this, the project has detailed the scope and plan to address Data Catalog and Data Quality requirements for grid modernization. Initial assumptions about the product and architecture for the Enterprise Data Platform were re-validated and the project has now finalized the software products for this project covering: Data Catalog, Data Quality, Data Store, and Visualization/Reporting.

In a subsequent Phase 2, key datasets will be loaded to a new, central data warehouse for storing, sharing, and integrating grid modernization data – for the purpose of facilitating analysis and decision-making to advance grid modernization objectives. Comprehensive capabilities will be delivered for the following:

- Extensible toolsets to enable asset management use cases requiring Data Visualization and Data Analytics
- Implementation and rollout of analytical toolsets and packages for investment decision making that are Predictive and Risk Based Analyses

Enterprise Integration Platform

The project has completed the setup of the core platform, which is the foundation on which the integrations to enable grid modernization will be delivered. Multiple environments to support development, test and production have been provisioned. The platform components include: Enterprise Service Repository, Business Activity Monitor, Complex Event Processor, Connectors/Adapters, Cloud Integration Platform, and Application Program Interface (API) Management. In addition to setting up this foundational capability in Phase 1, integrations across ADMS, GIS, Customer Service System (CSS), and TOMS will be delivered to align with overall grid modernization integration requirements.

In Phase 2, additional integrations that are required across the CNI boundary will be delivered. With these, more advanced integrations between the applications mentioned for Phase 1 and AMF, Outage Management, Work and Asset Management, Weather Applications, Load Forecasting, Energy Accounting Systems and Network Modeling Systems will be enabled.

Corporate PI Historian

The project will setup required infrastructure including hardware and software to install and configure the Corporate PI Historian system. The environment will include production, disaster recovery, development and testing. The scope of work also includes sourcing data from both Transmission PI and Distribution PI systems to have a centralized SCADA data repository for corporate users, which includes extracting data from non-RTU based systems, like Feedpro, to have a single unified PI Historian to store and manage data from both RTU and non-RTU data feeds.

Cost Estimate

Table 9.1 presents the 5-year cost estimates for the Underlying IT Infrastructure investments. The Company estimates investing $4.6 million through FY26. These costs would be recovered through the Company's rate case filings. Note that the Company also performed planning work from FY19 through FY21 to ensure the Company is fully prepared to execute the projects. This work is being performed utilizing existing resources in the current MRP. An overview of the work completed to date is provided in *Section 4.1: 2017 Rate Case Funding for Grid Modernization* in the GMP Business Case.

Table 9.1: Underlying IT Infrastructure Cost Estimates – 5-Year Plan

Underlying IT Infrastructure, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
Data Management CAPEX	$ 0.73	$ 0.47	$ 0.47	$ 0.03	$ -	**$ 1.69**
Data Management OPEX	$ 0.10	$ 0.05	$ 0.05	$ 0.01	$ -	**$ 0.21**
Data Management RTB	$ 0.10	$ 0.16	$ 0.16	$ 0.17	$ 0.17	**$ 0.75**
Enterprise Integration Platform CAPEX	$ 0.47	$ -	$ -	$ -	$ -	**$ 0.47**
Enterprise Integration Platform OPEX	$ 0.15	$ -	$ -	$ -	$ -	**$ 0.15**
Enterprise Integration Platform RTB	$ 0.10	$ 0.23	$ 0.23	$ 0.23	$ 0.23	**$ 1.03**
Corporate PI Historian CAPEX	$ 0.07	$ 0.09	$ -	$ -	$ -	**$ 0.16**
Corporate PI Historian OPEX	$ 0.01	$ 0.01	$ -	$ -	$ -	**$ 0.02**
Corporate PI Historian RTB	$ -	$ 0.03	$ 0.04	$ 0.04	$ 0.04	**$ 0.15**
Total	**$ 1.74**	**$ 1.04**	**$ 0.96**	**$ 0.48**	**$ 0.44**	**$ 4.65**

Note: Costs associated with Underlying IT Infrastructure for the incremental AMF investment are included in the AMF costs shown in Table 2.2.

10. Appropriate Cyber Services

Background

Cyber security is critical to managing the distribution system more granularly in order to reliably, safely, and cost-effectively meet customers' evolving expectations and provide them with greater choice and control in addressing their energy needs. Cyber and privacy threats may emerge as new, grid connected technologies are introduced. Monitoring and control capabilities must include cyber security solutions in the process rather than as a retrofit or after-thought. The following potential risks highlight why cyber security is necessary for developing a more granular distribution system:

- Greater complexity increases exposure to potential attackers and unintentional errors
- Networks that link more frequently to other networks introduce common vulnerabilities that may span multiple systems and increase the potential for cascading failures
- More interconnections present increased opportunities for "denial of service" attacks, introduction of malicious code (in software/firmware) or compromised hardware, and related types of attacks and intrusions
- As the number of network nodes increases, the number of entry points and paths that potential adversaries might exploit also increases
- Increased data gathering and shift towards two-way information flow increases the potential compromise of data integrity and confidentiality of data, resulting in potential data breaches, customer privacy intrusions or system compromise

Goals and Objectives

Proposed cyber security efforts will align with and leverage National Grid security services incorporating potential improvement opportunities and expected evolution of technologies and threats. Specific cyber security efforts will include:

- Expand integration between Corporate, CNI, and operational technology (OT) security architecture and operating model evolution in order to reduce security risk by increasing visibility, reducing complexity, and enabling the increased usage of existing capabilities
- Increase incorporation of formalized security practices and rules of engagement across project lifecycle activities, such as vendor acquisition and solution delivery, in order to support sustained security performance as business and technical operations evolve
  Assess cyber security risks associated with the introduction of new grid modernization capabilities, identifying and prioritizing risks based on potential impact and the likelihood of cyber security threat materializing
- Evaluate and implement, based on risk, key foundational improvements, such as baseline configuration management, logical access controls, and data governance, to better build

consistent security coverage, services, and processes across all business and technology functions

To further understand the cyber security improvements required, strategic risk analysis is undertaken to understand how cyber security threats may manifest in grid modernization applications and systems, and an impact analysis is completed to understand the potential impact and likelihood if a risk materializing. Based on the outputs of this analysis, improvement areas are identified and a plan of action is laid out to address cyber security threats in a coordinated and prioritized manner.

All systems, components, and integrations are considered in the following service domains described below: Network; Data Protection; Identity and Access Management; Vulnerability; Security Orchestration, Automation and Response (SOAR); Platform, Third Party Risk, and Training and Awareness. While these service domains currently feature foundational capabilities in place to support the current state of National Grid's operations and are improved on an on-going basis, further enhancement is required to ensure that the risk associated with grid modernization is mitigated through the deployment of security controls to address cyber security risk associated with the future state of grid operations.

Network

The Network service domain covers the protection of National Grid's CNI (e.g., core switches, routers, proxy gateways) against cyber-attacks—this includes limiting vulnerabilities in the network infrastructure and preventing unauthorized access, misuse, modification or denial of a network resource or the network itself. Network security relies on layers of protection and consists of multiple capabilities including network monitoring and security software in addition to hardware and appliances.

Network initiatives include the deployment of hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- Advanced log management adding event-reduction, alerting and real-time analysis functionality
- Agentless technology to interrogate network infrastructure, detect suspicious devices, programmatically limit access, and remediate at-risk endpoints
- Network taps that copy packets for monitoring and provide intelligent management capabilities that monitor link and power states of diverse connected devices
- Scan-less vulnerability assessment using intelligence repositories and advanced analytics to detect exposures on traditionally "un-scannable" distribution system devices and zones

Through the enablement of the capabilities across the Network area, grid modernization applications will benefit from network monitoring and alerting at the Cyber Security Operations Center and enhanced perimeter defenses that address cyber security related risk and improve operational efficiency.

Data Protection

The Data Protection domain provides the protection of data from accidental or intentional but unauthorized modification, destruction or disclosure using data protection solutions and other safeguards to ensure that confidentiality and integrity is maintained. Data Protection enables the proactive and appropriate management and protection of corporate data (in-motion and at-rest) on the Corporate Data Network based in accordance with business requirements.
Data Protection initiatives include the deployment of hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- Network and user activity monitoring, secure roaming users and mobile devices security, and global services management from a single management console
- Scalable agent-based data loss prevention using a hybrid premise/cloud-based solution to proactively tag/classify data
- Data discovery and automated classification labeling and asset tracking

Data Protection investments will reduce the risk associated with data theft, data loss or data integrity violations. Grid modernization transforms the way National Grid operates the grid, and this is completed through leveraging vast amounts of previously untapped data. Data Protection investments seeks to ensure that data is safe and secure throughout its lifecycle.

Identity and Access Management

The Identity and Access Management (IAM) domain provides the management of individual identities, and their authentication, authorization, and privileges/permissions within or across system and enterprise boundaries, with the goal of increasing security and productivity while decreasing cost, downtime and repetitive tasks. IAM's goal is to ensure that only authorized people can access resources in the enterprise.

IAM initiatives will deploy hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- Least-privilege access enforcement, and privileged activity monitoring/analysis complemented by policy-based outbound real-time alerts
- Privileged identity management capability for both physical and virtual environments by control oversight of privileged user access

- Policy-based authentication and single sign-on for web-based applications
- Critical files and registry keys protection from tampering, enforces policies, and reports on violation sources
- Remote access

Identity and Access Management will ensure a centralized approach to access throughout all grid modernization applications, ensuring that the correct levels of access are granted at the origin of identities and ensuring that those with elevated access are governed appropriately. Moreover, as identity theft is a leading cyber security threat across all organizations, Identity and Access Management will establish baseline behavioral information, enabling the alerting of anomalous individual behaviors that may be the result of identity theft.

Vulnerability

The Vulnerability domain provides proactive threat management and reactive response capabilities. This service will analyze logs and monitor applications and systems for abuse/misuse, provide intelligence around cyber-threats, scan both internal and external systems for vulnerabilities and compliance, analyze and support security patching, and provide around-the-clock (i.e., “24x7”) response capability.
The Vulnerability domain will:

- Optimize vulnerability scanning capabilities
- Establish a centralized asset lifecycle management
- Implement code scanning and centralized views of threat intelligence feeds and reporting

Vulnerabilities are inherent to all systems, applications and code. Grid modernization will introduce new applications to our environments that require real-time patch management, vulnerability scanning and a prioritized approach to vulnerability remediation.

Security Orchestration, Automation and Response (SOAR)

The SOAR domain provides a vital line of defense against unauthorized, malicious activity in real time. This requires employing the right people, technology and processes. The Company’s Security Operations Center, a team of well-equipped security analysts, is organized to prevent and report on cyber security risks, but even more importantly to detect, analyze and respond to incidents. It is a vital node in charge of the Company’s issues related to cyber security.

The SOAR domain will:

- Deploy hardware, software and the associated maintenance, services, and labor to enable logging and correlation of data and applications for real-time analytics

- Incorporate behavioral analysis to spot applications and protocols regardless of whether they are plain text or use advanced encryption and obfuscation techniques
- Enhance playbooks based on expanded visibility and conduct training on alert types

SOAR will provide the centralized capability for monitoring and event logging across all grid modernization systems, networks and applications, allowing for data collecting and log gathering, centralized into one platform. The SOAR platform will reduce risk across not only grid modernization investments, but throughout the organization as a more holistic view of security event data is consolidated and alerting is automated, reducing the reliance on manual intervention for event flagging.

Platform

The Platform domain provides protection of workstations, laptops, smartphones and tablets by enabling device encryption, secure configuration, and continuously protected operation. This service extends the monitoring and controlling of hosts and endpoints to meet the required standards. The service will monitor the state of endpoints (e.g., host assets like servers, laptops, desktops, smart devices) for threat indicators; investigate events to determine severity, accuracy, current capabilities, and future enhancements; and ensure critical events can be escalated to ensure effective management of security vulnerabilities.

The Platform domain will implement hardware, software and the associated maintenance, services, and labor to enable the following capabilities:

- File integrity and configuration monitoring
- Application whitelisting
- Baseline configuration standards definition and maintenance
- Cloud security skillsets and operating practices expansion

Grid modernization applications will benefit from the improved visibility and monitoring which aim to reduce the impact and duration of cyber events by alerting the presence of malicious content and preventing further infection onto interconnected systems.

Third-Party Risk

The Third-Party Risk domain provides software, hardware, and procedural methods to protect applications from external threats. This domain embeds within the software development process to protect the various applications that might be vulnerable to a wide variety of threats. Security measures built into applications and a sound application security routine minimize the likelihood that unauthorized code will be able to manipulate applications to access, steal, modify, or delete sensitive data.

The Third-Party Risk domain will ensure that:

- Policies or procedures are periodically reviewed, assessed, and updated, as necessary
- Third parties appoint positions and/or personnel to ensure security and privacy policies are properly maintained, updated, and followed
- Privacy practices are transparent

Third-party risks introduced by way of grid modernization will be addressed by ensuring that a coordinated approach is defined, specifically tailored to grid modernization and leverage processes already established to manage third-party risk at National Grid. Grid modernization will introduce a variety of third parties who will leverage National Grid data, information, infrastructure and services. Ensuring that these third parties do not increase the level of security risk when interacting with National Grid is critical.

Training and Awareness

The Training and Awareness domain is responsible for reducing the risk of a human error resulting in security breach by ensuring that customers, employees, contractors and third-party users are aware of information security policies, threats and concerns as well as their responsibilities and liabilities. The Security Awareness Program inculcates appropriate knowledge and attitudes regarding cyber security accountability and responsibility among all members of the business – including protection of the physical, but especially critical cyber assets (i.e., applications, application hosts, and the information that resides on and is communicated between systems).

There are several key objectives for the Training and Awareness domain, including:

- Obtaining and disseminating the latest cyber security news and trends from internal monitoring and external sources
- Establishing training plans and schedules for continuing cyber security education
- Developing, advocating, implementing and evaluating internal cyber security training programs that are needed to establish and maintain a continuously optimizing cyber security program
- Ensuring that the business is kept up to date with emerging security threats, vulnerabilities, attack methodologies, etc.
- Providing awareness of threats and risks to vital business processes
- Developing a "Culture of Security"
- Defining and supporting cyber security awareness program improvements

Grid modernization will require specific cyber security training and awareness campaigns targeting overarching awareness and training as well as role-specific training to ensure individual responsibilities are known and understood.

By integrating these functionalities in the existing networks, systems, and touch-points that are capable of exchanging information seamlessly, the older proprietary and often manual methods of securing utility services will give way to more open, automated and networked solutions. The benefits of this increased connectivity will depend upon robust security services and implementations that are necessary to minimize disruption of vital services and provide increased reliability, manageability, and survivability of the electric grid and customer services. Recognizing the unique challenges of grid modernization is imperative for deploying a secure and reliable solution.

Benefits

Cyber security provides protection of cyber assets (e.g., computer hardware and software, information) from theft, damage, disruption or misdirection of the services they provide. This functionality is a foundational element and supports all other key functionalities described in *Section 5.1.4: Functionality and Benefit Impacts Assessment* of the GMP Business Case.[7]

The importance of cyber security is increasing as more intelligent devices are interconnected and volumes of data increase along with an ever-growing cyber-attack surface. The need to maintain confidentiality, ensure data integrity, and improve resiliency is increasingly important as the Company leverages this information to drive more efficient operations and improve decision making.

Incorporating cyber security and privacy provisions into all grid modernization investments and activities will ensure the reliability of the electric distribution grid, with information integrity built in and the confidentiality of customer information maintained within various business processes addressing privacy concerns. The cyber security provisions built into grid modernization will provide for:

- Availability: avoid denial of service
- Integrity: avoid unauthorized modification
- Confidentiality: avoid disclosure
- Authenticity: avoid spoofing/forgery
- Access control: avoid unauthorized usage
- Auditability: avoid hiding
- Accountability: avoid denial of responsibility
- Third-party protection: avoid attacks on others

- Segmentation: limit the scope of attacks on the solution
- Quality of service: Maintain reasonable latency and throughput
- Privacy: Maintain customer data in a fashion that keeps confidential customer data confidential

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

The cyber security implementation plan calls for a phased roll out of security services, based on business priorities and risk reduction. A formal internal review will occur periodically to ensure that proposed cyber security and privacy services evolve along with ever-changing cyber threats. These threats will be monitored continuously to ensure that the systems and information that support customers remain protected and secured.

Status

Applicable cyber security threats have been mapped to the grid modernization business capabilities to assess how they may be impacted by those threats if they were to be realized. In addition, the implementation plan for the integration of cyber security services and the grid modernization workstreams have been drafted to ensure services are available when needed. During the next rate year, Appropriate Cyber Services will be deployed and/or enhanced to support the grid modernization workstreams, and detailed requirements and design will be started. Elements of cyber security have already been delivered as part of the Enterprise Service Bus investments (part of Enterprise Integration Platform).

Major Tasks

The approach leverages security capabilities inherent in grid modernization solutions as well as existing information security controls for protecting vital systems and operations. The cyber security implementation plan addresses, but is not limited to, the following concerns:

- Specifying security requirements as part of the selection criteria for grid modernization equipment, systems, and third-party service providers
- Monitoring and controlling access to all grid modernization equipment and systems
- Implementing appropriate cryptographic and other electronic security measures to strengthen the confidentiality and integrity of sensitive information during use, transmission, and storage
- Implementing appropriate redundancy and other features in grid modernization solution design to protect and enhance availability

- Employing secure or "hardened" configurations of hardware and software capabilities
- Employing strict access control and authentication methods to prevent unauthorized access to user and system accounts, web services and other system resources
- Providing appropriate malware protection for systems and relevant resources
- Maintaining ongoing processes to ensure security-related updates are identified, tested and implemented
- Providing continuous security monitoring for system intrusions and other unauthorized access
- Monitoring and tracking security events appropriately and integrating these events into a broader incident response and reporting process
- Ensuring compliance with existing enterprise cyber security standards
- Deploying solutions with the flexibility to upgrade and maintain compatibility with evolving government and industry security standards
- Requiring third-party smart grid vendors to maintain a proactive security process by utilizing a secure development lifecycle, conducting security testing on their solutions, and other appropriate activities
- Assessing the security posture of grid modernization systems, both periodically and event-driven (e.g., application, firmware, and hardware updates) via independent third-party cyber security testing
- Developing and implementing remediation plans for identified risks and emergent system vulnerabilities

The Company currently has a cyber security program, infrastructure, applications, systems, staff and operations. The GMP's cyber security implementation plan seeks to enhance existing capabilities where applicable and invest in new capabilities where no existing capability is fit for purpose.

Cost Estimate

Table 10.1 presents the 5-year cost estimates for the Appropriate Cyber Services investment. The Company estimates investing $1.6 million through FY 2026. These costs would be recovered through the Company's rate case filings. Note that the Company also performed planning work from FY 2019 through FY 2020 to ensure the Company is fully prepared to execute the projects. This work is being performed utilizing existing resources in the current MRP. An overview of the work completed to date is provided in *Section 4.1: 2017 Rate Case Funding for Grid Modernization* in the GMP Business Case.

Table 10.1: Appropriate Cyber Services Cost Estimates – 5-Year Plan

Appropriate Cyber Services, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
Cyber Security CAPEX	$ 0.77	$ 0.15	$ -	$ -	$ -	**$ 0.92**
Cyber Security OPEX	$ 0.05	$ 0.01	$ -	$ -	$ -	**$ 0.06**
Cyber Security RTB	$ 0.01	$ 0.14	$ 0.14	$ 0.14	$ 0.14	**$ 0.56**
Total	**$ 0.82**	**$ 0.31**	**$ 0.14**	**$ 0.14**	**$ 0.14**	**$ 1.55**

Note: Costs associated with Cyber Security for the incremental AMF investment are included in the AMF costs shown in Table 2.2.

11. Operational Telecommunications

Background

A secure and robust Operational Telecommunications (OpTel) network is a foundational element to the GMP. The Company currently utilizes several different communications technologies for the collection of customer meter and T&D system data. The existing communication networks include private fiber and microwave, along with commercial telecommunication carrier wireline and wireless services. While the existing OpTel network is suitable for current grid data requirements, it must be upgraded and expanded to support future grid modernization and enable greater reliability, control, monitoring, and security of the distribution assets.

Currently, the Company's OpTel network supports corporate functions, substations RTU/SCADA, off-site data center connectivity, and Company facility interconnections. A combination of wireless solutions and wireline connectivity such as fiber optic or copper wire cables make up the current OpTel network. Wireline communications are predominantly used between the substations and wireless communications is most often deployed at the network edge along a feeder or at a utility pole. The majority of the current OpTel network is owned and managed by commercial carriers where the wireless component is based on a public cellular network. These telecommunication carriers are now in the planning stages of eliminating leased communication via analog means and replacing them with digital methodologies. This requires a replacement of the Company's telecommunications terminal equipment to be compatible with the new digital service as well as replacing the copper lines with potentially fiber optic cables where it is cost effective to do so.

In addition to these traditional telecommunications needs, distribution grid assets (e.g., Sensors, Advanced Capacitors & Regulators, Advanced Reclosers & Breakers) and large DG facilities are increasing the Company's OpTel needs substantially. These assets and facilities currently utilize public cellular networks and a cellular gateway to bring the data back to the Distribution Control Center. The Company is responsible for the upfront and RTB costs for communications with large DG facilities, including monthly public cellular network fees and the upfront investments in cellular gateway capacity to bring the data back to the Distribution Control Center. The number and type of control devices connected by commercial public cellular are listed in Table 11.1. This represents the existing Advanced Field Devices currently deployed and used in Rhode Island.

Table 11.1: Advanced Control Devices By Program

Advanced Field Devices Installed by Program	VVO/CVR Pilot	Recloser Replacement	Large DG Facilities
Feeder Monitoring Sensors	44	0	0
Advanced Capacitors	122	0	0
Advanced Regulators	52	0	0
Advanced Reclosers	0	365	88
Total	**218**	**365**	**88**

While communications is possible to any DG facility that is willing to install a RTU or a point of common coupling (PCC) recloser with integrated relay, DG projects below 500 kW are not required to install these devices, so very few small DG facilities (<50 kW) have communications at this time. Note that PCC reclosers, when available, only enable on/off "control" of the site by dispatch when absolutely necessary and are not used for balancing the distribution system or for operational efficiency.

Large DG facilities require communications under the following conditions:

- 500 kW or larger facilities connected to 5 kV or lower distribution circuits
- 1,000 kW or larger facilities connect to higher than 5 kV but lower than or equal to 15 kV distribution circuits
- 1,800 kW or larger facilities connected to higher than 15 kV subtransmission circuits

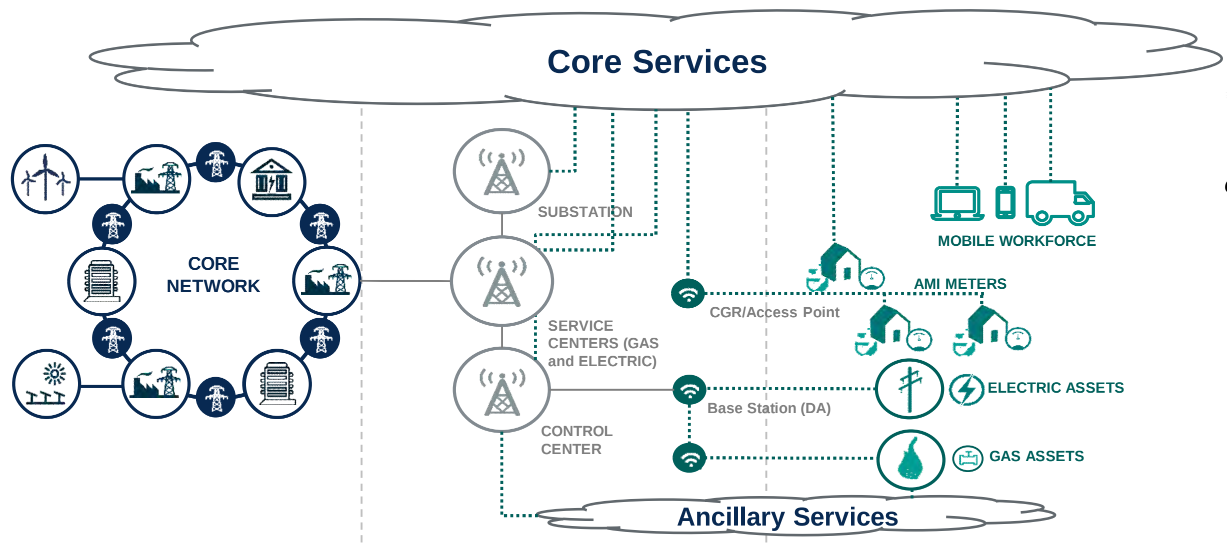
As of August 5, 2020, the Company had 671 public cellular devices associated with distribution grid assets and 445 public cellular devices associated with DG facilities connected to the distribution system. Note that while it is necessary for the Company to monitor Independent Power Producer (IPP) projects, including "utility-scale" solar PV and wind projects that are typically connected through the transmission system and participate in the ISO-NE markets, the Company is not responsible for managing or controlling these large scale IPP projects.[29]

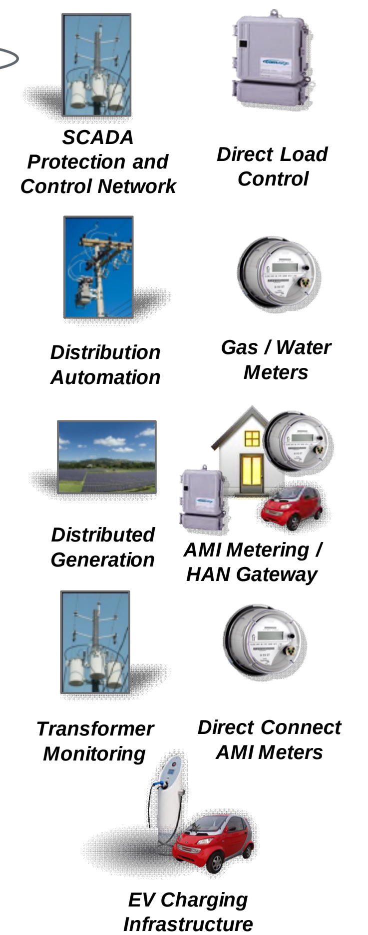
[29] These projects do not require an RTU, but pole top reclosers capture the Company needs for site monitoring and control. Pole top reclosers only enable on/off "control" of the site by dispatch when absolutely necessary, and are not used for balancing the distribution system or for operational efficiency.

The Company recently set out to understand how the Company's OpTel network and governance should evolve to cost-effectively meet the changing needs of customers and the protection, control, and monitoring of the Company's electric assets through 2030. The Company investigations reveal that opportunities exist to enhance performance and cost-effectiveness of OpTel through the development of a secure, private OpTel network to accommodate the Company's electric T&D systems.[30] The Company's strategy for the implementation of these near-term OpTel opportunities is referred to as the Company's OpTel Strategy.

OpTel networks are organized by network "tiers" as shown in Figure 11.1 below. This figure also provides a depiction on the right of the various technologies and services that are supported by the network across each tier.

[30] The extent to which the Company's natural gas system can benefit from a private network is still under evaluation at this time.





TIER 1: BACKBONE / CORE NETWORK	**TIER 2:** MID-TIER/ BACKHAUL NETWORK	**TIER 3:** FIELD AREA NETWORK (FAN)
◆ Core Network provides high-speed connectivity between major facilities and substation. ◆ Fiber & Microwave Network for critical applications such as teleprotection, SCADA, and security ◆ Solution options include redundant private fiber, redundant private licensed microwave depending on technical requirements	◆ High speed connectivity off the Tier 1 network to substations & facilities. Typically spurs off the core ring that does not require redundancy. ◆ Backhaul to tier 3 Network assets ◆ Solution options include private fiber, private licensed microwave, or private licensed Point to Multi-Point (PtMP) at 3.5GHz/5GHz depending on technical requirements	◆ Network for field applications & devices ◆ Wireless Mesh, Point to Multipoint, license and unlicensed spectrum for AMI, DA devices, SCADA and other similar applications ◆ Solution option is a licensed sub 1GHz Point to Multi-Point (PtMP) wireless connectivity, primarily for DA SCADA and Customer Substation connectivity

Figure 11.1: Telecommunications Tier Definitions

Tier 1 is the core network backbone consisting of leased circuits, private fiber, and private licensed microwave from which all data from Tier 2 and Tier 3 assets will traverse through into back office systems. Tier 2 is the mid-tier backhaul network of leased circuits, cellular, private fiber, private licensed microwave, and/or private licensed Point-to-Multipoint (PtMP) communication. Tier 3 refers to a field area network (FAN), which extends connectivity into the realm of the distribution system so that advanced grid devices and DER can be integrated with distribution grid operations. The primary access of the FAN is wireless using a combination of commercial cellular and privately licensed spectrum, which offers the highest level of control, reliability, and security. The FAN supports the Company's plans to integrate Sensors, Advanced Capacitors & Regulators, Advanced Reclosers & Breakers, and connected DER devices with the Distribution Control Center ADMS.

Goals and Objectives

OpTel Strategy

Considering the breath of communications options and the evolution of technology, the Company understands that a flexible strategy is required when deploying communication systems. In particular, the OpTel system must be designed in a fashion that permits an efficient refresh of network technologies. No single telecommunications network will economically meet all requirements in all areas. Therefore, the Company is planning for a private network across the service territory that provides coverage in a reliable and economic manner. The Rhode Island PUC and other stakeholders will have the opportunity to review the Company's updated and detailed OpTel Strategy plans in the next rate case filing.

The majority of the telecommunications costs for the OpTel Strategy are the costs to build and operate a private network, which will provide the majority of communications for the new distribution devices such as those supporting customer DERs. Aside from the added benefits of greater network control and reliability in transitioning from a public carrier solution to a private one, a key driver of this change is to reduce long-term costs (e.g., commercial cellular RTB costs) that increase with every new grid device added. Given all the grid modernization initiatives, plus increasing adoption of DG and future EV adoption, the Company anticipates a significant number of endpoint nodes that will need connectivity. Considering the two bookend DER adoption scenarios, the Company estimates that an additional 2,400 new distribution devices under the Low DER Scenario (85% field devices and 15% large-scale DER) and 11,400 new distribution devices under the High DER Scenario (30% field devices and 70% large-scale DER, primarily for commercial EV charging) will need to be outfitted with telecommunications and be connected into the Distribution Control Center systems.

The large increase in connected devices anticipated in the future would result in significant commercial cellular RTB costs if investments are not made in OpTel Strategy. With significant cost coming from increasing cellular connectivity, the justification of investing in a private network becomes stronger. Further expanding communications to the network edge, the Company is also considering using the same private network to deploy future technologies for AMF communications, which would be standards-based and more reliable than traditional systems.

As the number of network end nodes increases exponentially, the economic reasoning for deploying a private network over commercial cellular becomes evident and well-founded. Many utilities across the country have already begun the network transition from public to private. The Company is in contact with many of these utilities and has been engaged in technical exchanges. Most of the existing private network deployments utilize the same 700MHz spectrum the Company is considering for Rhode Island. This band is at the forefront due to is attractive value proposition especially given its low frequency and associated strong propagation,[31] which minimizes radio site count. A total of 19 utilities have purchased this spectrum for their service areas, some of which include: First Energy (OH), Salt River Project (AZ), Great River Energy (MN), Puget Sound Energy (WA), and CenterPoint Energy (TX).

The Company is in the early stages of planning and implementing the various recommendations from the OpTel strategy of expanding private wireline and wireless networks. In the interim (i.e., FY 2022-2024), while the Company develops and deploys the OpTel Strategy investments, the Company intends to leverage its existing networks and scale its cellular gateway as necessary to accommodate the increasing number of devices on the distribution system. During this period, the Company will continue to be responsible for the upfront and RTB costs for communications to these devices, including monthly commercial cellular network fees and the upfront investments in cellular gateway capacity to bring the data back to the Distribution Control Center. As the private network is being rolled out, these existing cellular radios may be used as failover on some of the more critical control nodes further increasing network availability.

Tier 1 & Tier 2

One of the biggest drivers of upgrading the telecom network with fiber connectivity is the commercial carriers' imminent plan of eliminating Digital Signal 0 (DS0)[32] analog leased lines to substations and replacing them with Transmission System 1 (T1)[33] or other digital technologies that may not be the most future-proof or appropriate for the proposed grid modernization initiatives. By proactively responding to this unavoidable directive brought on by the carriers, the Company will take the lead in network redesign and leverage on-going efforts, wherever possible, to cost effectively expand the reach of fiber optics. In order to enable the

[31] Propagation refers to the transmission of radio waves or signals through space, commonly referred to as network coverage.
[32] DS0 is a basic digital signaling rate of 64 kbits per second.
[33] T1 is a basic digital signaling rate of 1.54 Mbits per second.

GMP initiatives proposed, the existing rudimentary analog communications must first be upgraded to current technologies that support the new requirements for increased network performance, security, reliability, and control.

Eliminating the heavy reliance of commercial telecommunications carriers' antiquated analog technology is a major priority in updating the 110 substations across the State. Throughout the United States, commercial carriers are currently retiring analog circuits and shifting to new technology such as fiber optic cable, which is either significantly more expensive or just not viable as the cost of deploying fiber especially in rural areas is cost-prohibitive. Therefore, some of the site locations with existing analog will be left without any network connectivity as carriers terminate service. The Company's affiliate in New York is currently experiencing this in its New York service area where the impact and alternative solutions are proactively being assessed. The Company is leveraging lessons learned from our affiliate's experience, which will inform the Company's solution in Rhode Island.

Tier 3

An appropriate wireless radio and antenna is required at each control device (e.g. reclosers, capacitors, regulators), which allows communications back to the core network. The cost for these radios and their commissioning are accounted for in the cost estimates for the Advanced Field Devices included in the GMP and not in the telecommunications line items. However, investments included in this telecommunications section include any backhaul and receiver equipment costs as well as the cost of any on-going cellular data plans. Aside from the new cellular interconnections used to provide communications in the near term, the Company is evaluating a private FAN as a replacement to the existing cellular platform. The target Tier 3 solution will provide near ubiquitous FAN coverage throughout the Company's service territory allowing for an expansion of the network into the field (or "edge"), which will enable multiple grid modernization efforts through a communications path to the Company's back office systems.

Network Management

In addition to the needs to deploy the necessary OpTel Strategy, the Company must also enhance its ability to plan and manage this growing class of controllable assets. As part of the Network Management investment, the Company is reviewing its current methods, which lack features for graphical and logical circuit planning, design and evaluation. Adding new tools and developing interfaces to current systems will improve maintenance and operations. Existing manual practices cannot keep pace with the increasing volume and flexibility required for grid modernization. Therefore, the Company is progressing plans to implement a TOMS tool for the planning, engineering, commissioning, management and operations of the Company's OpTel systems that integrates with GIS, Work Management (WM), asset management system, and a future planned Integrated Network Operations Center (INOC).

With the need to manage the distribution system more granularly over the next ten years, TOMS will enable provisioning and management of the communications infrastructure to support this transformation and will replace the manual methods currently in place. The project will select, purchase, install and integrate the software with the ability to capture all pertinent data for telecommunications equipment and circuits utilizing both manual and automated data entry with mobile technology. TOMS will provide a single telecommunications asset repository tool that will facilitate the planning, engineering, operating and maintaining of existing assets as well as the future private electric telecommunication network. The tool will also streamline communications projects, improving the time to deploy and reducing costs through repeatable processes that capture all elements of the design and implementation of communications systems.

The existing methodologies for the planning, engineering, deployment and maintenance of National Grid telecommunications circuits and equipment use multiple manual processes, data bases, and information sources and heavily rely upon native knowledge of individuals that is at risk of being lost through attrition and retirement. As a result, the status of some telecommunications equipment is not readily known and often requires field investigation to identify the asset information and condition.

Once the current state of the existing network is captured and maintained within TOMS, the performance of the network will be managed by the INOC. The INOC will actively monitor, manage, and maintain the integrated set of communications-based services and infrastructure in a similar fashion as a Distribution Control Center manages the power grid. As with the carrier-grade NOC's of traditional telecom service providers, the INOC will provide real-time insight and control of network performance through a "single pane of glass" down to the lowest telecommunications asset (e.g., feeder monitor radio at the edge of the grid). Considering that there are many private wireline and wireless networks deployed throughout the Company using varying technologies, the INOC brings together all disparate NOC's into a single, centralized platform to maintain a high level of network performance across all National Grid telecommunications devices.

Benefits

Telecommunications provides highly reliable connectivity under both normal and degraded system operating conditions. This Operational Telecommunications functionality is a foundational element and supports all other key functionalities described in *Section 5.1.4: Functionality and Benefit Impacts Assessment* of the GMP Business Case.[7] Operational

Telecommunications functionality also results in two quantified benefit impacts that are summarized below.

- Avoided Legacy OPEX Investments by avoiding recurring RTB telecoms costs from existing Advanced Field Devices and future DERs. OpTel strategy will enable the Company to convert a majority of the existing commercial cellular communications to a private network, thus avoiding monthly cellular fees for existing Advanced Field Devices and future connected DERs. This Avoided Legacy OPEX Investment benefit is included in the GMP BCA as “field device RTB telecoms savings (existing)” and “DER RTB telecoms savings” (see Section 8.4.3: Benefit Estimation in the GMP Business Case).

- Avoided Legacy CAPEX Investments by avoiding the cost of converting from DS0 to T1 circuit technology in the near-future. Legacy DS0 telecommunications circuit technology is being obsoleted by commercial carriers. Without investment in an OpTel Strategy, the Company would need to convert the DS0 circuits to T1 circuit technology by replacing network equipment. This Avoided Legacy CAPEX Investment benefit is included in the GMP BCA as “DS0 to T1 telecoms savings” (see Section 8.4.3: Benefit Estimation in the GMP Business Case).

In addition, the hardened and enhanced core network of Tier 1 and 2 will act as a strong foundation upon which many forthcoming grid modernization initiatives may be added in the future, including backhaul in support of the private wireless network. Specific benefits identified in the OpTel strategy, but not quantified at this time, include:

- Operational savings as leased lines are replaced with technology that is more robust and flexible
- Tier 3 connectivity for devices on analog circuits where fiber is cost-prohibitive
- Operational efficiency and overall cost reduction due to combining the many disparate legacy telecommunications systems
- More reliable performance (e.g., uptime, capability) from Advanced Field Devices due to network reliability, flexibility, and scalability, especially where high availability and lower latency are required for devices to function properly. Only in operating a private wireless network can total control of field devices be accomplished to the highest levels of reliability.

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or described qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

The Company is still developing definitive OpTel Strategy implementation plans, and it is currently evaluating long-term plans to deploy private fiber and/or microwave technologies into substations and facilities to support currently deployed assets as well as future grid modernization solutions. The proposed fiber optic expansion work along with the wireless network build will take place in FY22-24 with the exception of fiber upgrades at the other key and critical facilities which will occur in FY25-31. Phases 2 and 3 of TOMS, which include the implementation of the software and the field survey respectively, will be conducted in FY 2022.

Status

Significant work has been initiated in evaluating new core network equipment (Tier 1 & 2), developing a private wireless network solution (Tier 3), evaluating incremental telecommunication bandwidth investments, and procuring and setting up TOMS that will maintain all telecommunications equipment and services (Network Management). For the greatest operational efficiency, each initiative is being developed across National Grid's Rhode Island, New York, and Massachusetts service areas because the same technology solutions and approaches are being considered and proposed for each state.

OpTel Strategy Tier 1 & 2

The Company is progressing upgrades to its core network, primarily at substations, through testing and evaluation of three leading equipment vendors. Following vendor selection, surveys of the substations will commence, and detailed hardware configurations and designs will then be produced. In the meantime, a limited investment in conversion of DS0 terminal equipment has been proposed under the FY21 ISR for substations requiring immediate action due to the commercial carrier's non-negotiable T1 conversion schedule.

OpTel Strategy Tier 3

The Company has compared affordable spectrum options and selected appropriate technology that will support requirements of the primary use cases. In advancing development of the proposed solution, detailed network coverage design involving site selection and qualification is being performed to arrive at an accurate total cost for the private network. Field testing will also begin in FY21 with multiple radio vendors covering various technologies and frequency bands.

Network Management

The Company initiated planning and scoping to engineer, design, manage, and deliver a network of devices and connectivity in collaboration with the preferred vendor for AMF. The Company also initiated the planning and scoping for the Data Lake and Advanced Analytics efforts, which will inform incremental telecommunication bandwidth investments. New telecommunication needs for AMF and other grid modernization investments will continue through the next rate year.

The Company has also finalized evaluation and procurement of the TOMS software. Next steps are to survey and inventory all telecommunications assets throughout Rhode Island. Only in having a detailed snapshot of the current network topology and capability can other network enhancements be implemented in the most efficient manner.

Major Tasks

OpTel Strategy Tier 1 & 2

Work activities and associated Tier 1 and 2 network upgrades are similar in nature across all the initiatives of increasing fiber connectivity to analog locations, critical and key facilities, and teleprotection sites. At the highest level, the proposed tasks involve the design, build, and operation of newly connected fiber sites. Much of the network design includes cost analysis of whether to install private fiber or use existing service provider circuits. For routes that are shorter in length (i.e., a few miles), the cost often justifies use of private fiber. The majority of the cost for the fiber network build is attributed to the construction of trenching cable in the ground or suspending it on utility poles. A smaller component is the procurement, configuration, and installation of network gear (switches and routers) at the endpoint locations – most often occurring at the distribution substations. RTB costs involve the O&M of the hardware, which given the high reliability of the electronics, a more favorable total cost of ownership may be realized for private wireline networks on sites with these shorter fiber runs.

OpTel Strategy Tier 3

Over the last 30 years, the cost model for deploying wireless networks has been perfected and optimized by the cellular carriers. In designing and building out the private wireless network in Rhode Island, the Company will follow this deployment model and approach. The design phase begins with radio site selection where coverage and capacity are modeled using sophisticated network planning tools. Existing radio sites such as microwave or land mobile radio (LMR) will be leveraged to reduce cost and establish the anchor design. Site acquisition companies responsible for leasing, zoning, and permitting will assist in identifying other commercial radio sites or new towers located at select substations. Commercial construction companies specializing in radio network builds will perform the deployment work outside of installations in and around power lines. In the Operations phase (i.e., RTB-related work), while the Company currently self-performs these tasks related to network performance, maintenance, and field work, additional contracted O&M services with mission-critical service level agreements (SLA) will be considered to support the increased work load. Outsourcing a good part of O&M on large networks is common in the wireless industry where efficiencies exist in service companies maintaining multiple independent networks around the clock (e.g., state networks involving police or transit along with other municipality or federal networks).

The acquisition of spectrum used for the wireless network is a standard transfer of ownership through the Federal Communications Commission (FCC). Should the Company decide to proceed with a spectrum acquisition, then the expected time frame in completing change of ownership is expected to be approximately 4-6 months.

Network Management

The Company released a request for proposals (RFP) soliciting a telecommunication tool for planning, engineering, commissioning, management, and operations that will enable improved design and documentation as well as telecommunications asset management. This tool will also enable process change and improvement as it is rolled out and provide for documentation and coordination of alarm and monitoring for the network. The tool allows for logical mapping of circuits through most all media including multiple fiber splices and routing.

Cost Estimate

Tables 11.2 and 11.3 presents the 5-year cost estimates for the OpTel Strategy and Network Management investments. The Company estimates investing about $39 million through FY 2026. These costs would be recovered through the Company's rate case filings. Note that the Company also performed planning work from FY 2019 through FY 2021 to ensure the Company is fully prepared to execute the Network Management projects. This work is being performed utilizing existing resources in the current MRP. An overview of the work completed to date is provided in *Section 4.1: 2017 Rate Case Funding for Grid Modernization* in the GMP Business Case. Details on the OpTel Strategy plan and investments will be presented in the next rate case.

Table 11.2: Operational Telecommunications Strategy Costs – 5-Year Plan

OpTel Strategy, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
OpTel Strategy CAPEX	$ 9.73	$ 10.15	$ 6.78	$ 1.56	$ 1.56	**$ 29.79**
OpTel Strategy OPEX	$ 0.40	$ 0.27	$ 0.13	$ 0.02	$ 0.02	**$ 0.83**
OpTel Strategy RTB	$ -	$ 0.24	$ 0.55	$ 0.76	$ 0.81	**$ 2.36**
Total	**$ 10.13**	**$ 10.66**	**$ 7.46**	**$ 2.34**	**$ 2.39**	**$ 32.97**

Table 11.3: Network Management Costs – 5 Year Plan

Network Management, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
Network Management CAPEX	$ 1.21	$ 1.33	$ 0.89	$ 0.47	$ -	**$ 3.90**
Network Management OPEX	$ 0.13	$ 0.05	$ 0.05	$ 0.09	$ -	**$ 0.32**
Network Management RTB	$ 0.10	$ 0.10	$ 0.10	$ 0.58	$ 0.58	**$ 1.47**
Total	**$ 1.44**	**$ 1.48**	**$ 1.05**	**$ 1.14**	**$ 0.58**	**$ 5.70**

Note: Costs associated with Operational Telecommunications for the incremental AMF investment are included in the AMF costs shown in Table 2.2.

12. Volt-Var Optimization (VVO)/Conservation Voltage Reduction (CVR)

Background

Volt-VAR Optimization (VVO) is an integrated approach to tie voltage and reactive power (VAR) control field devices (e.g. Advanced Capacitors & Regulators) together on one distribution feeder so the field devices work in unison and provide the most efficient delivery of power to the customer. Through VVO, the Company can manage the voltage levels and reactive power, and better manage delivery of power to our customers. Utilizing VVO with Conservation Voltage Reduction (CVR) technology can flatten and lower feeder voltage profiles through the use of Sensors and centralized control of Advanced Capacitors & Regulators based on real-time system performance.

The VVO control schemes currently being demonstrated under Rhode Island's VVO/CVR Pilot program coordinate multiple voltage regulating devices on a feeder to achieve optimal CVR benefit. This lowering of feeder voltages benefits customers by reducing customer demand and energy use. Based on the Rhode Island VVO/CVR pilot deployments and M&V to date, benefits are an average 3% reduction in energy demand on the targeted feeders when VVO is operating. Customer benefits are realized through reduced costs for electric energy and system capacity, which result in lower customer energy bills.

To accomplish the coordinated operation necessary to achieve VVO/CVR benefits, Advanced Capacitors & Regulators including substation voltage regulating devices (i.e., Load Tap Changers (LTC) or individual phase regulators), line voltage regulators and capacitors must be deployed. In addition, Sensors will need to be added at the end of each feeder and at strategic points on the feeder to monitor power quality. Details on these deployments are described in *Section 4: Feeder Monitoring Sensors* and *Section 5: Advanced Capacitors & Regulators*.

Goals and Objectives

Beyond the voltage management described in *Section 5.1.4 Advanced Capacitors & Regulators* for compliance with voltage standards, the Company plans to continue to deploy VVO/CVR on targeted feeders where it is cost beneficial to do so. The Company is currently utilizing a stand-alone VVO/CVR controller for its VVO deployments but anticipates transitioning to an ADMS-based VVO/CVR solution to reduce costs and gain efficiencies due to automation onto a single control platform with an "as switched" network model allowing optimized solutions when the grid is in abnormal states. In the third phase of the ADMS deployment, the Company expects customer level voltage information to be available through AMF and believes an incremental 1% reduction in energy and peak demand can be achieved if this more granular voltage data is used to fine tune the VVO control scheme.[34] This additional 1% improvement is included as a benefit in the AMF BCA presented in the updated AMF Business Case.

Benefits

VVO/CVR platforms provide Power Quality Management functionality, which results in the quantified benefit impacts summarized below.[7]

- Avoided Legacy OPEX Investments by avoiding the cost of a standalone VVO/CVR license for existing deployments. Without investment in an integrated ADMS-based VVO/CVR application, the Company would need to continue to maintain its existing standalone VVO/CVR software license. This Avoided Legacy OPEX Investment benefit is included in the GMP BCA as "standalone VVO/CVR license savings (existing)" (see Section 8.4.3: Benefit Estimation in the GMP Business Case).

- Avoided D-System Infrastructure (when coupled with Advanced Capacitors & Regulators, Advanced Reclosers & Breakers, ADMS, and other supporting solutions) due to the ability of the system operator to autonomously or remotely control power flows on the distribution system, by maintaining voltage compliance across all times of the year and across the distribution system with various levels of DER penetration, rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption.

- Reduced Customer Energy Use and System Capacity Requirements (when coupled with Sensors, Advanced Capacitors & Regulators, and other supporting solutions) by enabling the system operator to manage voltage impacts of renewable DERs and operate

[34] AEP Ohio is currently testing a new Utilidata VVO/CVR module that takes voltage data from AMI and applies proprietary algorithms to find the most relevant information for fine tuning a VVO scheme. This new technology has been deployed in 16 feeders and in its first 6 months of operation is yielding on average 1%+ incremental energy savings. Source: Utilidata, Case Study: Maximizing Grid Modernization Investments.

distribution feeders at lower overall voltages (within ANSI limits) to reduce electricity consumption and peak demand from customer appliances

Specific benefits have been quantified in Section 8.4 Quantitative Benefit Cost Analysis or descried qualitatively in Section 8.6 Qualitative Assessment.

Schedule

The proposed VVO/CVR plan assumes the current stand-alone VVO/CVR platform continues to be expanded through FY 2024, after which an ADMS-based VVO/CVR application is implemented. The ADMS Core Functionality presented in Section 4 will be capable of supporting an integrated VVO/CVR application and the Company anticipates that a VVO/CVR application will be incorporated in the third phase of the ADMS project. Estimated VVO Central Control deployment schedules are included in the Schedule subsection within *Section 5.1.4: Advanced Capacitors & Regulators*.

Status

The Company has deployed Advanced Field Devices and VVO/CVR on select feeders over the last 3-5 years. The Company has deployed VVO/CVR capability through approved investments in Sensors, Advanced Capacitors & Regulators, and a Stand-alone VVO/CVR Control Platform through Company's VVO/CVR Pilot program funded through annual ISR filings. To date, the Company has implemented VVO/CVR on 19 feeders from 6 substations in Rhode Island. Deployment on an additional 14 feeders is anticipated through the Company's VVO/CVR program in the FY 2021 ISR Plan[35] based on the initial positive results.

Major Tasks

The Company plans to continue to deploy VVO/CVR on targeted feeders where it is cost beneficial to do so. Implementing the VVO/CVR platform central control scheme includes engineering planning, design, procurement, office testing, training, installation, field testing and M&V of the full system.

The Company is currently utilizing a Stand-alone VVO/CVR Controller for its VVO deployments. Costs for the standalone controller include one-time software license and professional services fees per feeder (CAPEX), annual integration and M&V support per feeder (CAPEX), Company administrative and engineering support (OPEX), and annual software maintenance fees per feeder (RTB). A future ADMS-based VVO/CVR solution will reduce costs

[35] *See The Narragansett Elec. Co. d/b/a National Grid, 2021 Electric Infrastructure, Safety, and Reliability Plan,* Docket No. 4995 (Submitted December 20, 2019).

due to lower Enterprise-level software license fees and gain efficiencies due to automation onto a single control platform.

Cost Estimate

Table 12.1 presents the 5-year cost estimates for the VVO/CVR platform investment under the High and Low DER customer adoption scenarios. The Company estimates investing between $4.8 and $7.9 million through FY 2026, depending on customer DER adoption. The initial stand-alone VVO/CVR platform costs will continue to be recovered through the ISR, but the future ADMS-based VVO/CVR application costs will likely be recovered through the Company's rate case filings. As can be seen, the cost estimates assume the stand-alone VVO/CVR platform used today continues to be expanded through 2024, after which an ADMS-based VVO/CVR application is implemented, which is estimated to reduce overall costs.

Table 12.1: VVO/CVR Platform Cost Estimates – 5-Year Plan

VVO/CVR Platform, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
High DER Scenario						
Stand-alone VVO/CVR CAPEX	$ 0.74	$ 2.21	$ 2.21	$ -	$ -	**$ 5.15**
Stand-alone VVO/CVR OPEX	$ 0.10	$ 0.32	$ 0.32	$ -	$ -	**$ 0.73**
Stand-alone VVO/CVR RTB	$ -	$ 0.09	$ 0.36	$ 0.63	$ 0.63	**$ 1.71**
ADMS-based VVO/CVR App CAPEX	$ -	$ -	$ 0.01	$ 0.10	$ 0.10	**$ 0.21**
ADMS-based VVO/CVR App OPEX	$ -	$ -	$ 0.00	$ 0.02	$ 0.02	**$ 0.03**
ADMS-based VVO/CVR App RTB	$ -	$ -	$ -	$ 0.01	$ 0.01	**$ 0.02**
Total	**$ 0.84**	**$ 2.61**	**$ 2.90**	**$ 0.76**	**$ 0.76**	**$ 7.86**
Low DER Scenario						
Stand-alone VVO/CVR CAPEX	$ 0.74	$ 1.23	$ 1.23	$ -	$ -	**$ 3.19**
Stand-alone VVO/CVR OPEX	$ 0.11	$ 0.18	$ 0.18	$ -	$ -	**$ 0.46**
Stand-alone VVO/CVR RTB	$ -	$ 0.08	$ 0.22	$ 0.36	$ 0.36	**$ 1.02**
ADMS-based VVO/CVR App CAPEX	$ -	$ -	$ 0.01	$ 0.06	$ 0.06	**$ 0.12**
ADMS-based VVO/CVR App OPEX	$ -	$ -	$ 0.00	$ 0.01	$ 0.01	**$ 0.02**
ADMS-based VVO/CVR App RTB	$ -	$ -	$ -	$ 0.01	$ 0.01	**$ 0.02**
Total	**$ 0.84**	**$ 1.48**	**$ 1.64**	**$ 0.43**	**$ 0.43**	**$ 4.83**

13. Fault Location, Isolation and Service Restoration (FLISR)

Background

The distribution system is generally a radial design, meaning that if the flow of electricity is interrupted at one location, all customers electrically downstream of that faulted location are interrupted as well. Reliable distribution system design utilizes protective devices such as fuses, breakers, and reclosers to interrupt faults and limit the number of customer interruptions as best as possible for any given fault. In addition, switches are placed at strategic locations along a feeder and where feeders can be connected to another feeder so that faulted sections of a distribution feeder can be isolated and power can be re-directed to customers in undamaged areas.

Currently, the initial clearing of electrical faults is done automatically with autonomously controlled reclosers and fuses, however the isolation of the faulted sections and the service restoration of customers is performed through the manual operation of switches in the field. Without an overlaying control scheme, an operator must first assess the extent of and determine the cause of an outage by dispatching crews. After crews investigate and report in, the operator can make a decision on how best to isolate the cause. This, again, involves dispatching crews to various location in a time-consuming fashion.

Distribution Automation, commonly referred to as FLISR, is a control scheme that incorporates telecommunications and advanced control of key switching devices. This scheme provides remote monitoring and operator control of field devices for normal operations and maintenance, while at the same time providing an automated response to system contingencies. Automated feeder tie points and protective devices (i.e., advanced reclosers) are coordinated to isolate faults and restore service to unaffected sections of a circuit without causing thermal or voltage violations. Coordination can be achieved via cellular communications with an ADMS-based FLISR Application.

This automation scheme positively impacts the resulting customers interrupted and customer minutes interrupted (CMI) performance from a fault event that occurs within the zone of protection. Based on the results of a FLISR pilot operated by the Company's Massachusetts affiliate,[36] and additional analysis, expected benefits are an average 25% reduction in sustained outage frequency and duration on feeders with sufficient Advanced Reclosers & Breakers and a FLISR control scheme. Customer benefits are realized through reduced outages costs, which are monetized using the DOE ICE Calculator.[17]

[36] *See* Worcester Smart Grid pilot, Appendix 10.8 to the Updated AMF Business Case.

To accomplish the coordinated operation necessary to achieve FLISR benefits, manual switches and feeder ties need to be upgraded to Advanced Reclosers & Breakers at selected three-phase mainline locations to allow for automated switching in the case of a contingency event. In addition, monitoring (e.g., Sensors) need at the end of each feeder and at strategic points on the feeder to monitor loading. Details on these deployments are described in *Section 4: Feeder Monitoring Sensors* and *Section 6: Advanced Reclosers & Breakers*.

Goals and Objectives

The Company is committed to providing reliable service to all customers. As a key service quality metric, reliability is measured by the frequency of customer interruptions and the duration of those interruptions. Metrics monitored in Rhode Island include System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI).

As more and more reclosers with advanced controls are deployed and integrated with the Distribution Control Center systems described in *Section 5.1.5: Advanced Reclosers & Breakers*, the automation of isolation and service restoration is possible. Switching steps that could take an hour or more now may be possible in less than one minute. To achieve this, feeder tie switches will need to be outfitted for remote control and a centralized FLISR control scheme application enabled on the ADMS platform. Targeted FLISR field deployments will be identified through planning studies and incorporated into annual ISR plans. The targeted field deployment will be aligned with the deployment described in *Section 5.1.5*.

The driver for FLISR is customer reliability, and the benefits and costs at each targeted location have been evaluated considering the expected impact on the frequency of sustained customer interruptions (i.e., SAIFI) and the duration of customer interruptions (i.e., SAIDI) that could be saved through automation.

Benefits

FLISR primarily provides Reliability Management functionality, but FLSR also enhances Distribution Grid Control and Grid Optimization functionalities.[7] Reliability Management functionality results in the quantified benefit impacts summarized below.

- Reduced Outage Restoration Time (when coupled with Advanced Reclosers & Breakers, ADMS, and other supporting solutions) by enabling the system operator and control system to quickly locate and isolate a fault and restore power to unaffected customers rather than waiting for field crews to locate a fault and restore power. Benefits are based on the monetization of customer impacts as presented in the DOE ICE Calculator.[17]

Additional benefits addressed qualitatively, include:

- Increased system visibility reduces time to patrol for a fault
- Providing a platform for a more sustainable and storm (minor and major) capable grid for the future
- Operational effectiveness through remote monitoring and control capability

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

The Company plans to begin deployment of and ADMS-based FLISR application after ADMS Phase 3 is complete in FY25-26. FLISR capabilities are anticipated to be available starting in FY27. The application would be deployed on all feeders with advanced reclosers where it is cost-beneficial according to the Docket No. 4600 Framework.

Status

The Company does not have any active programs to deploy FLISR.

Major Tasks

The Company plans to deploy FLISR on targeted feeders where it is cost beneficial to do so. Implementing the FLISR control scheme includes engineering planning, design, procurement, office testing, training, installation, field testing and M&V of the full system.

A future ADMS-based FLISR solution is anticipated to be very cost-effective due to relatively low-cost Enterprise-level software license fees. Costs estimates for FLISR include one-time software license and professional services fees per feeder (CAPEX), annual integration and M&V support per feeder (CAPEX), Company administrative and engineering support (OPEX), and annual software maintenance fees per feeder (RTB).

Cost Estimate

Table 13.1 presents the 5-year cost estimates for the FLISR investment. The Company estimates investing less than $0.12 million through FY 2026. These costs would be recovered through the Company's rate case filings. The costs shown are only the initial cost for FLISR implementation, which is not assumed to be fully implemented until the end of FY 2026 at which point annual RTB costs from software license maintenance fees would begin to apply.

Table 13.1: FLISR Cost Estimates – 5-Year Plan

Fault Location, Isolation, and Service Recovery, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
ADMS-based FLISR App CAPEX	$ -	$ -	$ -	$ 0.00	$ 0.10	**$ 0.10**
ADMS-based FLISR App OPEX	$ -	$ -	$ -	$ 0.00	$ 0.02	**$ 0.02**
ADMS-based FLISR App RTB	$ -	$ -	$ -	$ -	$ 0.00	**$ 0.00**
Total	**$ -**	**$ -**	**$ -**	**$ 0.00**	**$ 0.12**	**$ 0.12**

14. Distributed Energy Resource Management System (DERMS)

Background

The deployment of advanced grid devices and the implementation of ADMS will enable the Company to more granularly operate the grid. To better integrate customer controlled DER resources with grid operations, an additional suite of tools called DERMS is expected to be necessary. The flagship role of a DERMS is to dispatch DER in a manner that maintains the security of the distribution system while ensuring an optimal economic solution. To do so, DERMS must have functionalities that include resource registration, forecasting, resource optimization, activation, M&V, and settlement.

The Company's initial DERMS experience has been in support of the Company's demand response (DR) programs, which are generally supported through a Demand Response Management System (DRMS) and behind-the-meter (BTM) DERs rather than a complete BTM and front-of-the-meter (FTM) DERMS. A full suite of DERMS tools may be functionally similar to a DRMS but would provide enhanced functionality as it relates to DERs, particularly FTM DERs. Rhode Island currently employs a suite of DRMS/BTM DERMS applications to manage its various DR programs including:

- EnergyHub for Commercial and Industrial (C&I) programs
- EnergyHub for residential programs
- Questline for behavioral DR emails
- Alteryx and Tableau for analysis and reporting
- DNV-GL Forecaster for forecasting and activation
- Send Word Now for notifications
- Itron IEE for real time data from C&I interval meters
- GridForce to track all C&I DR sales leads
- InDemand to track all incentive processing and reporting

Currently, the Company's DR programs primarily focus on reducing the bulk system (i.e., ISO New England) peak and there is only limited integration with distribution grid operations.

Goals and Objectives

An objective of the GMP is to better leverage DER and customer programs, including DR but also DG, EV charging, and energy storage, in support of distribution grid operations. As such, the long-term plan is to expand and enhance the types of resources that can be managed through a DERMS and to integrate DERMS with ADMS to optimize distribution grid performance. The Company expects that DERMS functionalities will be deployed as the applications become available and are beneficial to support grid and market operations.
DERMS must have a basic set of tools and functionalities that include the following:

- **Registration:** database of interconnected DER assets along with pertinent details associated with ownership, operations, operating parameters, and program enrollment and rules needed for real-time operations that are not currently collected as part of the DER registration process. If programs allow for aggregations, it will also support managing aggregation data and relationships.

- **Forecasting:** application to forecast behind-the-meter (BTM) and FTM assets at a premise or feeder level. This forecast helps in operating the grid (e.g., feeder switching or reconfiguration analysis) by providing more succinct data associated with varying technologies, which can help to better forecast unmasked/gross load.

- **Resource Optimization (e.g., Economic Dispatch):** modeling and applications associated with planning and optimization of grid and market operations, such as a secure economic dispatch considering resources available.

- **Activation:** application to notify DERs when energy dispatch is needed to initiate a wholesale or retail program.

Other tools, including M&V and Settlement are not expected to be needed until there is significant DERMS-connected DER penetration and a robust market, like a distribution-level transactive energy or services market. The Company expects the scope and scale of desired DERMS functionalities will increase and evolve as customer DER adoption increases and new programs for load management (e.g., DR, flexible DG, energy storage, EV charging, microgrids) become available.

Since the DERMS is a "set" of applications that collectively provides the evolving grid modernization requirements, the Company plans to develop a DERMS application roadmap to understand the best approach and options to satisfy the requirements while providing the necessary interfaces, security, and functionality for the near- and long-term. Note that this set of applications may include existing tools and applications or enhancement of existing tools and applications, and not necessarily new investments. The Company's future DERMS may also include or even replace current DRMS/BTM DERMS solutions.

Benefits

DERMS primarily provides DER Operational Control functionality, but DERMS also enhances Grid Optimization functionality.[7] DER Operational Control functionality results in the quantitative benefit impact summarized below.

- Reduced DG Curtailment (when coupled with Advanced Reclosers & Breakers, ADMS, and other supporting solutions) due to the ability of the system operator optimize power output from renewable DG, by rearranging the distribution feeders and maximize the load-to-generation balance, rather than relying on seasonal curtailment to maintain thermal and voltage compliance

Additional benefits addressed qualitatively, include:

- Improved DER Experience can be realized (when coupled with ADMS) by streamline DER interconnections and potentially reducing interconnection costs and enabling larger DER interconnections, which can make DERs more cost effective to deploy in the State

Specific benefits have been quantified in *Section 8.4 Quantitative Benefit Cost Analysis* or descried qualitatively in *Section 8.6 Qualitative Assessment*.

Schedule

The timing of need for DERMS functionality is dependent on readiness of appropriate DERMS functionalities, DER penetration, evolving DER policy requirements, evolution of wholesale and retail markets and customer programs, and the need for enhanced operational and economic dispatch. The Company's DERMS application roadmap development plan, based on the expected timing of need for the DERMS functionality and expected readiness of appropriate DERMS functionalities, is summarized below:

- 1-3 years – utilize DRMS/BTM DERMS applications for registration, forecasting, and activation
- 3-6 years – deploy applications such as distribution system impact modeling
- 5+ years – integrate DERMS and ADMS Phase 3 processes for distribution planning and operations

It should be noted that DERMS applications, especially those that are model-based, may take 1-3 years to develop and become functional.

Status

The Company does not have any active programs to deploy DERMS specifically targeting areas with significant levels of DER penetration, where these capabilities can be leveraged to support the efficient operation of a distribution system with high amounts of DER. However, the Company has deployed a DRMS in support of its energy efficiency DR programs, which can be considered a BTM DERMS in that it is being used to manage Wi-Fi thermostats, electric vehicles, batteries, generators, CHP, HVAC systems, lighting systems, industrial processes, and other BTM DERs. Current BTM DERMS functionalities include handling customer/vendor registration, event dispatch, and performance calculations. However, the management of FTM resources such as power plants, solar farms, and Company-owned resources are not within the purview of the energy efficiency portfolio.

The Company has included a smart inverter demonstration in the 2021 Energy Efficiency Plan. If approved, this demonstration will improve power factor and provide voltage support of the distribution system. If this demonstration is successful, the Company will look to build on these capabilities and add others as necessary to enable greater control to support the efficient operation of a distribution system.

Major Tasks

Over the next five years, the Company plans to conduct the following DERMS related activities:

- Continue mapping operations and market functionalities to available DERMS capabilities
- Perform DERMS demonstration projects as needed to test new functionalities
- Evaluate vendor offerings against the Company's standards and requirements
- Seek ways to integrate DERMS functions with ongoing projects to realize synergies
- Develop a business case for the future deployment of DERMS applications
- Benchmark DERMS activities across the industry

Like ADMS, DERMS will provide a platform on which to scale new program applications. It is envisioned that DERMS will be a set of applications that are tightly integrated with ADMS and Distribution Control Center operations, and thus there would be one instance in New England to cover both Rhode Island and the Company's Massachusetts affiliate.

Cost Estimate

Table 14.1 presents the 5-year cost estimates for the DERMS investment. DER adoption level is not specified because these costs are assumed to not change based on DER adoption level.

However, DERMS investment could potentially be delayed under the Low DER Scenario. The Company estimates investing about $8 million through FY 2026. These costs would be recovered through the Company's rate case filings. The costs shown are only the initial cost for DERMS implementation, which is not assumed to be fully implemented until FY 2027. Refined plans and costs estimates will be developed through DERMS Roadmap development and ITR Project work.

Table 14.1: DERMS Cost Estimates – 5-Year Plan

Distributed Energy Resource Management System, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
DERMS CAPEX	$ -	$ 1.00	$ 1.00	$ 1.00	$ 1.00	**$ 4.00**
DERMS OPEX	$ -	$ 1.00	$ 1.00	$ 1.00	$ 1.00	**$ 4.00**
DERMS RTB	$ -	$ -	$ -	$ -	$ 0.28	**$ 0.28**
Total	**$ -**	**$ 2.00**	**$ 2.00**	**$ 2.00**	**$ 2.28**	**$ 8.28**

15. Innovation and Technology Readiness (ITR) Projects

Background

Key uncertainties associated with the GMP include the pace and scale of technological advancement, and the development of complementary programs and services to be leveraged in the management of the distribution grid. A precise future state is difficult to predict due to the many factors that influence future demands on the distribution system, including future federal, state and local policies; technology developments, options and their costs; market maturity, regulatory hurdles; and customer preferences. This uncertainly creates risks with respect to the scope and timing of investments within the GMP and the benefits to be achieved.

The Company has taken several steps to better understand these uncertainties and manage the associated risks, most notably creating a 10-year roadmap and 5-year implementation plan to guide the development of projects and programs. Moving forward on our grid modernization journey in Rhode Island, the Company proposes to continue to develop a better understanding of these uncertainties and manage risks by undertaking Innovation and Technology Readiness (ITR) projects. ITR projects are small-scale pilot projects designed to mimic important aspects of key topics/investments of the GMP that require further investigation prior to full-scale roll out, thereby reducing the risks to rate payers. Through the ITR projects, the Company will continue to engage with the GMP and AMF PST Advisory Group and participate in grid modernization technology evaluation in order to refine the assumed future state scenarios, BCA, and the GMP's sequenced plan of investments, so they can be reviewed and adjusted throughout the horizon of the plan.

Goals and Objectives

ITR Project investments will fund the pilot projects necessary to support cost-effective deployment of the future grid modernization investments presented in the GMP, particularly investments that are less-well defined, like DERMS, or investments with emerging functionality that can be further explored to increase net benefits, like the System Data Portal, AMF, ADMS, VVO/CVR, or FLISR. This approach is similar to the Company's successful VVO/CVR Pilot program being funded through annual ISR filings. ITR projects will enable the Company to work with the industry to evaluate and test early versions of some of the future GMP solutions and functionalities on a small scale, so the most cost-effective and beneficial functionalities and use cases can be developed for large-scale deployment.

In addition, grid modernization capabilities are evolving as these initiatives are being advanced across the U.S. and globally. ITR projects will enable the Company to pilot and evaluate additional emerging grid modernization capabilities, functionalities, and use cases that could add to the benefits or reduce the costs presented in this GMP. Finally, the horizon of the GMP spans more than 10 years and because of that, the maturity of the cost and benefit estimates presented and utilized in the BCA are of varying levels of accuracy. The ITR projects will help improve the current cost and benefit estimates leading to better estimation of the overall GMP BCA results and gain key insights and lessons learned to inform future full-scale deployment.

Benefits

ITR Projects will increase the GMP success through testing of novel use cases and functionalities of the key solutions identified in the GMP, in a low risk manner, to help solidify and verify the associated costs and quantitative and qualitative benefits. Overall, ITR projects will help identify and evaluate GMP innovation and technology readiness opportunities, and will enable the Company to implement grid modernization as quickly and cost-effectively as possible and provide the most value to customers. Specifically, ITR projects will enable the Company to:

- Evaluate the feasibility of new technologies based on smaller-scale pilots before making large-scale investments (akin to the Company's existing VVO/CVR Pilot)
- Consider options to help future-proof GMP investments for technology and value shifts and help mitigate the risk of obsolescence
- Reevaluate and refine expected customer and societal benefits
- Share knowledge and lessons learned with RI stakeholders and implement best practices for continuous improvement

- Help to de-risk elements of GMP prior to full-scale roll out including identification and assessment of potential partners and vendors
- Allow the Company and its staff to gain familiarity and training of key GMP functionalities ahead of full-scale roll out

In these ways, ITR Projects have the potential to support a number of key functionalities described in *Section 5.1.4: Functionality and Benefit Impacts Assessment* of the GMP Business Case.[7]

Schedule

The Company anticipates completing up to three ITR projects in each of two phases coinciding with two future rate case periods, or up to six projects total over six years. Completion of each phase is assumed to be over the term of each rate case (i.e., 3 years each).

Prior to making specific ITR project proposals, the Company will develop a prioritized and coordinated plan with the Company's affiliates in Massachusetts and New York, which have similar planned or on-going pilot projects.

Status

ITR Project investments will fund the pilot projects necessary to support cost-effective deployment of the future grid modernization investments presented in the GMP. There are no active ITR programs in the formal sense. However, the ITR Project approach is similar to the Company's successful VVO/CVR Pilot program being funded through annual ISR filings. The on-going VVO/CVR Pilot has tested out different VVO/CVR technology configurations and solutions, including different communications solutions, some of which were unsuccessful. But, due to the small-scale deployment nature of the pilot, these unsuccessful solutions were able to be identified and replaced, such that the overall VVO/CVR program cost and performance impacts were minimized. ITR projects will support the technology readiness of new investments that will enable the Company to explore additional customer value and other opportunities above and beyond the VVO/CVR Pilot program.

Major Tasks

The Company anticipates prioritizing one ITR project per topic area consistent with GMP goals and objectives. Topic areas will explore new capabilities, functionalities, and/or use cases in the following areas:

- Customer Programs (e.g., TVR for distribution-level DR, enhanced System Data Portal tools)

- Reliability Improvements (e.g., artificial intelligence for reliability)
- System Safety (e.g., arc flash and adaptive protection tools)
- Renewable DG (e.g., advanced smart inverter modeling and control for flexible interconnections)
- Beneficial Electrification (e.g., EV charge management)
- DER Management (e.g., DERMS investigation)

Overall, ITR Project investment will be based on the expected cost to complete the selected projects in each topic area considering elements of the GMP that have: 1) high potential benefits or other value, 2) reasonably high uncertainties or risks for full-scale deployment, and 3) sufficient time to conduct on a small scale prior to full-scale roll-out. If a project appears unlikely to achieve its objectives (e.g., cost savings, performance improvements, scalability) during the course of the evaluation or testing, the Company will seek to fail fast, obtain key lessons learned, and any remaining funding would be transitioned to another project concept that has similar potential and is in the same topic area.

The Company plans to engage with Rhode Island stakeholders in both the planning and evaluation phases of the ITR projects. For example, the Company proposes to meet with key Rhode Island stakeholders (e.g., OER, Division, GMP and AMF PST Advisory Group) twice annually to review the existing ITR Project portfolio, provide updates to existing projects, and discuss potential future projects. The Company could also meet annually with other interested parties to discuss the key ITR Project activities and lessons learned.

Cost Estimate

Table 15.1 presents the 5-year cost estimates for the ITR Project investment. The Company estimates investing $4 million through FY 2026, depending on selected pilot project needs. The Company anticipates selecting 2-3 ITR topic areas and prioritizing one project per topic during each phase, resulting in between 4 to 6 projects total over two rate case periods. CAPEX and OPEX estimates are based on an assumed 60/40 split typical of pilot projects. These costs would be recovered through the Company's rate case filings. The costs shown are only the initial cost for ITR Project implementation, which is not assumed to be completed until FY 2027.

Table 15.1: ITR Project Cost Estimates – 5-Year Plan

Innovation & Technology Readiness Projects, $ million ($2020)	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	5-Yr Tot
	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY22-26
ITR Phase 1 CAPEX	$ -	$ 0.60	$ 0.60	$ 0.60	$ -	**$ 1.80**
ITR Phase 1 OPEX	$ -	$ 0.40	$ 0.40	$ 0.40	$ -	**$ 1.20**
ITR Phase 2 CAPEX	$ -	$ -	$ -	$ -	$ 0.60	**$ 0.60**
ITR Phase 2 OPEX	$ -	$ -	$ -	$ -	$ 0.40	**$ 0.40**
Total	**$ -**	**$ 1.00**	**$ 1.00**	**$ 1.00**	**$ 1.00**	**$ 4.00**

APPENDIX

Table of Contents

1. Acronyms

ADA = Advanced Data Analytics
ADMS = Advanced Distribution Management System
AMF = Advanced Meter Functionality
AMI = Advanced Meter Infrastructure
AMR = Automated Meter Reading
ANSI = American National Standards Institute
API = Application Programming Interface
ARI = Active Resource Integration
ASA = Amended Settlement Agreement
AVR = Automatic Voltage Regulation
BCA = Benefit Cost Analysis
BCR = Benefit Cost Ratio
BE = Beneficial Electrification
BTM = Behind-the-Meter
ccEHP = Cold Climate Electric Heat Pump
CEATI = Centre for Energy Advancement through Technological Innovation
CEMP = Customer Energy Management Platform
CEP = Customer Engagement Plan
CIS = Customer Information System
CO_2 = Carbon Dioxide
CPP = Critical Peak Pricing
CSS = Customer Service System
CVR = Conservation Voltage Reduction
C&I = Commercial and Industrial
DA = Distribution Automation
DCFC = Direct Current Fast Charging
DEC = Duke Energy Company (North Carolina)
DER = Distributed Energy Resource
DERMS = Distributed Energy Resource Management System
DG = Distributed Generation
DLM = Dynamic Load Management
DMX = Data Multiplexer
DOE = Department of Energy
DPAM = Distribution Planning & Asset Management
DPU = Department of Public Utilities (Massachusetts)
DP&L = Dayton Power and Light (Ohio)
DR = Demand Response
DRIPE = Demand Reduction Induced Price Effect
DSCADA = Distributed Supervisory Control and Data Acquisition
DSIP = Distributed System Implementation Plan
DSP = Distributed System Platform
DSPx = Next-Generation Distribution System Platform
D-System = Distribution System
EBU = Electric Business Unit
EC4 = Executive Climate Change Coordinating Council
EDI = Electronic Data Interchange
EE = Energy Efficiency
EEPP = Energy Efficiency Program Plan
EHP = Electric Heat Pump
EIA = Energy Information Administration
EMS = Energy Management System
EM&V = Evaluation, Measurement & Valuation
EPRI = Electric Power Research Institute
ESB = Enterprise Service Bus
EV = Electric Vehicle
FAN = Field Area Network
FCC = Federal Communications Commission
FLISR = Fault Location Isolation and Service Restoration
FTE = Full-time Equivalent (Employee)
FTM = Frond-of-the-Meter
FY = Fiscal Year
GBC = Green Button Connect My Data

GBD = Green Button Download My Data
GDP = Gross Domestic Product
GHG = Greenhouse Gas
GIS = Geographical Information Systems
GMP = Grid Modernization Plan
HAN = Home Area Network
HCA = Hosting Capacity Analysis
HECO = Hawaiian Electric Company
ICE = Interruption Cost Estimate
IEEE = Institute of Electrical and Electronics Engineers
IoT = Internet of Things
ISO-NE = Independent System Operator New England
ISR = Infrastructure, Safety, and Reliability
IT = Information Technology
ITR = Innovation and Technology Readiness
kV = Kilovolt
kVA = Kilovolt-Ampere
kW = Kilowatt
kWh = Kilowatt hour
LDV = Light Duty Vehicle
LED = Light Emitting Diode
LMP = Locational Marginal Price
LPG = Liquefied Petroleum Gas
LVA = Locational Value Analysis
MA = Massachusetts
MDMS = Meter Data Management System
MECO = Massachusetts Electric Company
MPLS = Multi-Protocol Label Switching
MRP = Multi-Year Rate Plan
MV/LV = Medium Voltage/Low Voltage
MW = Megawatt
MWh = Megawatt hour
M&V = Measurement and Verification
NCCETC = North Carolina Clean Energy Technology Center
NEC = National Electric Code
NEM = Net Energy Metering
NEP = New England Power
NMPC = Niagara Mohawk Power Corporation
NO_x = Oxides of Nitrogen
NPP = Non-Regulated Power Producer
NPV = Net Present Value
NY = New York
NYPSC = New York Public Service Commission
NWA = Non-Wires Alternative
OER = Office of Energy Resources
OMS = Outage Management System
OpTel = Operational Telecommunications
ORU = Orange and Rockland (New York)
O&M = Operations and Maintenance
PCS = Public Service Commission (New York)
PI Historian = Plant Information Historian
PII = Personal Identifiable Information
PIM = Performance Incentive Mechanism
PLC = Power-Line Communication
PMO = Project Management Office
PMP = Point-to-Multipoint
PPE = Personal Protective Equipment
PSE&G = Public Service Electric and Gas Company (New Jersey)
PST = Power Sector Transformation
PUC = Public Utilities Commission
PV = Photovoltaic
P2G = Power-to-Gas
REC = Renewable Energy Credit
REG = Renewable Energy Growth
REMI = Regional Economic Models, Inc
REV = Reforming the Energy Vision
RF = Radio Frequencies
RFP = Request for Proposal
RFS = Request for Solution
RGGI = Regional Greenhouse Gas Initiative
RI = Rhode Island
RTO = Regional Transmission Organization
RTU = Remote Terminal Unit
RY = Rate Year

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index
SCADA = Supervisory Control and Data Acquisition
SCE = Southern California Edison (California)
SCT = Societal Cost Test
SEPA = Smart Electric Power Alliance
SME = Subject Matter Expert
SO_2 = Sulphur Dioxide
SRP = System Reliability Procurement
TOU = Time Of Use
TRC = Total Resource Cost
TVR = Time Varying Rate
T&D = Transmission and Distribution
T-D = Transmission-Distribution (Interface)
Var = Volt/Volt-Ampere Reactive
VVO = Volt-Var Optimization
WACC = Weighted Average Cost of Capital
WAN = Wide Area Network
3V0 = Zero Sequence Over Voltage Protection

2. Efforts in Other States

National Grid is not the only utility facing the challenges of an evolving energy landscape. In January 2019, Smart Electric Power Alliance (SEPA) released a report titled "Understanding and Evaluating Potential Models for the Future Electric Power Utility"[1], which drew upon key insights from their 51st State Initiative Phase III Summary Report. Most utilities today operate by being primarily reactive to DER deployment, facilitating interconnection and integration to maintain reliability and power quality, but not by proactively encouraging DER deployment or controlling dispatch. This reactive "DER Interconnection and Integration" business model, as SEPA labels it, can be adjusted to ensure robust market competition, innovative offerings from third parties, and consumer choice. However, a key challenge to this reactive model is that it may miss opportunities to create value for individual customers and collectively through the grid.

According to the U.S. Department of Energy (DOE), today's electric grid lacks "the attributes necessary to meet the demands of the 21st century and beyond."[2] Grid modernization, then, would refer to any and all efforts to bring the electricity grid into alignment with current and future needs. While the term has been used to encompass a broad array of initiatives, common themes include improving the grid's responsiveness, interactivity, and resilience.[3] Drivers of grid modernization across the country include emerging technologies, evolving consumer demands, cybersecurity concerns, extreme weather events, and a broadly shared desire – among utilities, regulators, policy makers, and the public – to reduce the greenhouse gas (GHG) emissions associated with electricity production and support the development of low-carbon energy infrastructure.

Interest in grid modernization among utilities and utility regulators has increased in recent years. Because it involves identifying and prioritizing a suite of near-term investments in new and emerging technologies to enable unprecedented capabilities in an uncertain future, grid modernization is among the most complex challenges that utilities, regulators, and stakeholders grapple with today. Consequently, the Company's efforts to address grid modernization in Rhode Island, and the leadership shown by the Rhode Island PUC in this area, are of national interest and significance.

The North Carolina Clean Energy Technology Center (NCCETC), a North Carolina State University affiliate that tracks grid modernization developments across the U.S., reported in April 2020 that the U.S. saw its busiest quarter yet for state and utility grid modernization

[1] Understanding and Evaluating Potential Models for the Future Electric Power Utility, SEPA (2019), https://sepapower.org/resource/understanding-and-evaluating-potential-models-for-the-future-electric-power-utility/
[2] https://www.energy.gov/grid-modernization-initiative
[3] https://nccleantech.ncsu.edu/wp-content/uploads/2019/05/Q12019_gridmod_exec_final.pdf

activity since NCCETC began tracking grid modernization activity in 2017. Forty-seven states and the District of Columbia took actions related to grid modernization during Q1 2020.4 Notable recent grid modernization developments in other states include:

- In 2018, the Missouri legislature, energy companies, customers, business organizations, and Missouri leaders collaborated on passing landmark energy legislation (Missouri Senate Bill 564) that modernized Missouri's energy policies, enabling the Smart Energy Plan. The $6.3 billion Smart Energy Plan,[5] filed with Missouri regulators included $1 billion for wind energy plus investments to boost solar, storage, and reliability. In February 2020, Ameren Missouri filed an updated Smart Energy Plan with the Missouri Public Service Commission. The five-year plan increased investments to $7.6 billion in continued grid modernization while leveraging the successes from the first year[6].

- The Hawaii PUC approved the first phase of Hawaiian Electric Companies' (HECO's) four-year, $86 million grid modernization plan, which includes AMF deployment and enhanced data management.[7] In September 2019, HECO submitted their application for Phase 2, which focuses on ADMS.[8]

- In Minnesota, Xcel Energy filed their Integrated Distribution Plan in November 2019, which includes plans for investments in AMF, OpTel Strategy, FLISR, and VVO. Xcel Energy intends to formally request approval for the investments and bring forward the costs and benefits for the MPUC's approval through future IDP/grid modernization filings or as part of a general rate case.

- While action on grid modernization by utilities and utility regulators is of primary interest in this docket, notable recent federal-level actions include a clean economy legislation package in the House in June 2020 (under the broader H.R. 2). The package includes $3.5 billion to support investments that will improve the reliability, resilience, and

[4] "Activity" can fall into any of the following areas: studies and investigations; planning and market access; utility business model and rate reform; grid modernization policies; financial incentives for energy storage and advanced grid technologies; and deployment of advanced grid technologies, https://nccleantech.ncsu.edu/wp-content/uploads/2020/04/Q12020_gridmod_exec_final.pdf
[5] http://ameren.mediaroom.com/2019-02-15-Ameren-Missouri-releases-plan-to-transform-states-energy-grid-to-benefit-customers-and-communities
[6] https://www.amereninvestors.com/investor-news-and-events/financial-releases/financial-releases-details/2020/Ameren-Missouri-boosts-Smart-Energy-Plan-after-completing-900-projects-in-first-year-of-plan-to-transform-energy-grid-to-benefit-customers-and-communities/default.aspx
[7] https://www.hawaiianelectric.com/first-phase-of-grid-modernization-plan-approved
[8] https://www.hawaiianelectric.com/clean-energy-hawaii/grid-modernization-technologies/grid-modernization-strategy

security of the electric grid, citing grid modernization as necessary to integrate growing number of renewable and distributed energy.[9, 10]

As this summary shows, grid modernization is a complex, wide-ranging issue (or set of issues) that utilities and commissions have approached in different ways. It is possible, however, to identify common themes of successful efforts. These include the establishment of a strong value proposition; a gradual, phased approach; a clear vision for proposed investments, expressed in a detailed roadmap; robust stakeholder engagement; and utility accountability for delivering results. All of these elements have been incorporated into the RI GMP.

3. Examples of Current DER-Related Issues

3.1 System Impacts

Specific examples of instances where the Company would have been unable to maintain system reliability or safety due to DER projects are summarized below. Each example includes the issue encountered, the resulting reliability or safety impact, the methodologies deployed by the Company to resolve the reliability or safety issues, and the cost incurred by the Company to implement the solution.

- **Example 1**: During witness test of a 1,250 kW solar DG project, measurements of the primary system line to ground voltage exceeded 105%. Per Company requirements, DER restoration schemes are set to only reclose for voltages within +/-5% of nominal. In order to ensure auto-restoration would occur, system voltage needed to be reduced. Resolution: In order to reduce system voltage, a feeder capacitor was taken offline and seasonal settings were implemented to avoid high voltage during minimum loads. Estimated cost incurred by the Company for the setting changes was <$5,000.

- **Example 2**: During the analysis of a 216 kW solar DG project proposing to interconnect to a circuit served by the Clarkson Street Substation, it was determined that 3V0 was required but triggered prior to this proposed interconnection. Resolution: Leveraged existing 3V0 program to install required protection scheme at Clarkson Street substation. Estimated cost incurred by the Company for the Distribution Substation portion of 3V0 was $52,000.

- **Example 3**: During analysis of a 2,000 kW solar DG project proposing to interconnect to a circuit served by the Farnum Pike Substation, a pre-existing high voltage condition was identified at minimum feeder loads that would be exasperated with the interconnection of

[9] https://tonko.house.gov/news/documentsingle.aspx?DocumentID=3077
[10] https://www.utilitydive.com/news/pge-may-answer-the-billion-dollar-grid-modernization-question/561146/

the DG. Resolution: System modification were implemented including replacing three capacitors with advanced controls, updating capacitor settings on two units, and changing station load tap changer settings. The Company was responsible for the costs associated with these specific modifications, because they were considered system improvements. Estimated cost incurred by the Company was in the range of $100,000.

- **Example 4**: Adverse impacts identified during analysis of a 9,750 kW photovoltaic solar project proposing to interconnect to a circuit served by the Hopkins Hill Substation, which was a subtransmission supplied distribution line. Issues included high voltage, excessive voltage fluctuation, and desensitizing of existing protective devices. Resolution: Methods proposed to resolve the issues include reducing project size by at least 64% (i.e., from 9,750 to 3,500 kW), reconductor about 8,500 feet of overhead conductor, upgrade line recloser with advanced controls, and install bi-directional regulator controls. The estimated cost for these system modifications are being developed as part of the System Impact Study.

3.2 DER Project Impacts

Although the Company does not formally track reasons behind DER project cancellation and project size (MW) reduction, Table 3.1 summarizes projects the Company recollects where the construction cost and timeline to integrate a DER resulted in negative economic impacts or significant project size decrease that resulted in a DER project cancellation or suspension.

Table 3.1: Examples of DG Project Reductions due to High Interconnection Costs

Original Size / Decreased Size	Driver for Decrease	Comments
Cancelled Projects		
6,120 / 2,750 kW (55% reduction)	Overload	Engineering analysis identified potential conductor overloads with the interconnection of 6,120 kW. To accommodate the full 6,120 kW, substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 2,775 kW and about 12,000 feet of reconductoring was required to avoid the costly system upgrades. Customer was informed of required system modifications during the study and high-level costs of $1.4M to $1.8M for reconductoring were provided during early stages study. Option to decrease project size to 2,000 kW to avoid reconductoring was also presented.
10,000 / 3,150 kW (68% reduction)	Overload	Engineering analysis identified potential conductor overloads with the interconnection of 10,000 kW. To accommodate the full 10,000 kW, substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 3,150 kW and about 17,160 feet of reconductoring was required to avoid the costly system upgrades. Customer was informed of required system modifications during the study and high-level costs of $2.0M to $2.6M for reconductoring were provided. Option to decrease project size to 1,1000 kW to avoid reconductoring was also presented.
6,720 / 2,200 kW (67% reduction)	Non-compliance with Voltage ANSI Range A/ Power Quality/ Overload/ Protection Concerns	Engineering analysis identified unacceptable voltage and fluctuation issues, equipment overloads, and saturation of equipment on the area electric power system. To accommodate the full 6,720 kW, substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 2,200 kW with the following system modifications was required to avoid the costly system upgrades: replace 900 kVar capacitor with advanced control unit, enable co-generation on circuit regulators, replace multiple reclosers with units integrated with advanced controls, install two new reclosers integrated with advanced controls, install zero sequence over voltage protection (3V0) on the substation transformer. Total estimates including cost to extend the area electric power system to the site were approximately $1.3M.
3,000 / 200 kW (93% reduction)	Protection Concerns	Engineering analysis identified the need for 3V0 protection on the station transformer with the interconnection of 3,000 kW. DG project size reduction to 200 kW was required to avoid the 3V0 upgrade.

Table 3.1: Examples of DG Project Reductions due to High Interconnection Costs

Original Size / Decreased Size	Driver for Decrease	Comments
4,500 / 996kW (78% reduction)	Overload	Engineering analysis identified potential high voltage and conductor overloads caused by reverse power flow with the interconnection of 4,500 kW. Taking into account minimum circuit loading and prior DG applications, there was not enough hosting capacity on the feeder for a 4,500 kW project. To accommodate the full 4,500 kW, substantial modifications would be required. DG project size reduction to 996 kW was required to avoid the costly system upgrades. Customer was informed of required system modifications during the study and high-level costs estimates for required modifications. Option to decrease project size to 996 kW to avoid costly modifications was also presented.
Suspended Projects (Study Phase)		
4,500 / 750 kW (83% reduction)	Overload/ Non-compliance with Voltage ANSI Range A/ Protection Concerns	Engineering analysis identified potential high voltage, conductor overload, and protection issues with the interconnection of 4,500 kW. Major system modifications required to accommodate 4,500 kW included replacing station recloser and control with hardware capable of load encroachment schemes, changing existing protective device settings at multiple locations, installing approximately 15,000 feet of underground cable, and reconductor approximately 30,000 feet of overhead conductor. DG project size reduction to 750 kW was required to avoid the costly system upgrades.
6,360 / 2,180 kW (66% reduction)	Overload/ Non-compliance with Voltage ANSI Range A	Engineering analysis identified unacceptable voltage ranges on the area electric power system. To accommodate the full 6,360 kW substantial modifications such as a new circuit, substation, or major transmission project would be required. DG project size reduction to 2,180 kW with the following system modifications was required to avoid the costly system upgrades: re-conductor approximately 8,500 feet of overhead conductor and replace existing 167 kVA line regulators with 333 kVA units integrated with advanced controls. Estimated cost for these system modifications were approximately $2M. Option to decrease project size to 1,040 kW to avoid reconductoring was also presented. Reduced estimate for system modifications were approximately $1M.

4. Distribution Planning Process

4.1 Planning Analysis Approach

Planning can be conducted in a variety of manners including area studies, complex customer interconnection studies, program studies, targeted reliability studies, and yearly screening analysis. All analysis methods follow general problem solving steps such as:

- Scoping and Data Gathering
- Modeling
- Issue & Opportunity Identification
- Alternative Analysis
- Plan Recommendation

Data gathering includes collecting all information to conduct the analysis. As an example, collecting the latest forecast information and converting it into modeling input is a data gathering activity. Similarly, applying the appropriate criteria or standards during the analysis is another activity. Finally, collecting all the equipment details, including connectivity, settings, and analog quantities, is within the data gathering step. Currently, analog quantities include a mix of data obtained through the Energy Management System (EMS) and through manual meter readings. Most of this data is substation site information. There are currently few distribution line meters to obtain recorded data or read manually.

Modeling is done by importing equipment connectivity data into an analysis program such as CYME.[11] The analysis tools typically use equipment databases to automatically assign equipment characteristics to the connectivity data. For newer, inverter-based, equipment like solar DG, the characteristics must be manually entered. Then the analog information and forecast data is entered into the model.

With the model complete, a detailed system assessment can be conducted to identify issues and opportunities. Analysis tools have been developed over time using feedback from the utility users to the software providers. Voltage, percent loading, protection system coordination, and reactive compensation are examples of system performance analyzed in distribution studies. Other analysis topics such as asset condition reviews and reliability reviews are done outside of the load flow model. Which analysis topics are reviewed and to what level is determined by the planner based on the purpose of the individual study. For example, a reactive compensation review can be abbreviated to focus on voltage issues within an area. In the recent past, the detailed system assessment was conducted using peak load levels. Today, due to increasing DER penetrations, the Company studies two cases - peak and light load levels. The light load

[11] http://www.cyme.com

levels are determined through EMS data, or approximations where EMS data is not available. Similarly, DER performance at these periods is a mix of metered and approximated data. The current analysis tools have limited ability and the planners have limited data to study power or energy other than peak and light load times (i.e. across the hours of a year).

Once the analysis is complete and the issues and opportunities identified, the planner develops alternatives. The alternatives can be traditional pole and wires alternatives, non-wires alternatives (NWA), or a mix of both. In many cases, the Company collects industry information for NWAs through requests-for-proposal (RFPs).

The recommended plan is determined through economic analysis of the alternatives. In cases where the alternatives are only traditional poles and wires type investments that follow the same utility revenue requirement method, and address the issues in similar manner, a direct cost comparison is used. With alternative sets that include DER with much different economic factors and in consideration of ancillary and societal benefits beyond the system assessment, a more complex BCA is needed such as the one used for this GMP, which follows the Docket No. 4600 Benefit Cost Framework.

4.2 Study Boundaries and Tools

Before applying the Docket No. 4600 Benefit Cost Framework, study boundaries were established. First, the study horizon was established as 2030, which is in alignment with the GMP requirements, consistent with study horizons used in traditional planning studies, and is reasonable considering DER development uncertainty. Next, the forecast and forecast inputs to be studied were determined. The Company's current Electric Peak Load (megawatt) forecast includes consideration for weather, economic development, energy efficiency (EE), distributed generation (DG), and limited demand response (DR) and electric vehicles (EV). This forecast is focused on peak impacts that occur during summer and winter periods. To evaluate the Framework, it was apparent that the forecast needs to be modified to include daily and yearly load cycle information. Furthermore, increases to the forecast levels for distributed generation, to better align with the most recent trends, and increases to forecast levels for electric vehicles and electric heat pumps were considered to align with potential customer expectations were considered. The last study boundary was to establish the geographic and electrical limits of the analysis. The geographic boundary of the GMP is the State of Rhode Island and the study is limited to the electric distribution system as this system is the fundamental focus of this GMP.

After study boundaries were established, the study tools must be considered to determine if the inputs require adjustment. The existing distribution analysis tools have limited ability for load cycle analysis necessary for the Docket 4600 No. BCA development. Hour increments were selected as a reasonable interval aligned with industry trends. This resulted in forecasted data for 8760 hours per year for 12 years across 6 components (i.e., Economic Growth, Energy

Efficiency, Solar Distributed Generation, Wind Distributed Generation, Electric Vehicles, and Electric Heat Pumps), for a total of more than 600,000 data points.

5. Load Forecasting Details

5.1 Future State Scenarios

The Company developed a set of possible customer DER adoption scenarios for consideration as part of the GMP. The GMP uses the range of DER adoption assumptions in the scenarios to evaluate the range of impacts the Company could expect on the distribution system in the future. The two "bookend" scenarios evaluated in the GMP BCA are summarized below.

- Low Customer DER Adoption (Low DER) Scenario – Conservative adoption of renewable DG, EVs and EHPs based on historic (2018-2020) DER adoption rates with a 10% annual reduction in renewable DG adoption over time; DER adoption assumptions are consistent with the "Low Case" of the Company's 15-year distribution planning forecast.[12]

- High Customer DER Adoption (High DER) Scenario – Higher adoption of a range of DER technologies including renewable DG, EV and EHP consistent with achieving Rhode Island's 2050 goal of 80 percent GHG emissions reductions compared to a 1990 baseline (i.e., 80x50 Goal); DER adoption assumptions are consistent with the "High Case" of the Company's 15-year distribution planning forecast and are similar to Rhode Island's Executive Climate Change Coordinating Council (EC4) Greenhouse Gas Emissions Reduction Plan.[13,14]

Both scenarios are defined by their 2030 customer DER adoption assumptions summarized in Table 5.1. The DER assumptions are based on the Company's review of industry forecasts and input from internal subject matter experts. Details are also presented in *Section 3.2: Future State Scenarios* in the RI GMP Business Plan document.

[12] The Company assessed the probability of the Low Case occurring to be between 5-20%, depending on the DER load forecast. Specifically, Solar DG, EVs, and DR forecasts were assigned a probability of 5% each, Energy Efficiency was assigned a probability of 10%, and EHPs, which don't have a significant impact on the overall GMP cost or benefit assessment, were assigned a probability of 20%.
[13] The Company assessed the probability of the High Case occurring to be between 5-35%, depending on the DER load forecast. Specifically, Solar DG forecast, which has a significant impact on the overall GMP cost and benefit assessment, was assigned a probability of 35%; EV forecast was assigned a probability of 10%; and Energy Efficiency, DR, and EHP forecasts were assigned a probability of 5% each.
[14] EC4 *Rhode Island Greenhouse Gas Emissions Reduction Plan* (December 2016).

Table 5.1: 2030 Customer DER Adoption Assumptions for Future State Scenarios

2030 Future State Scenario Assumptions	1) Low DER	2) High DER
EVs On-Road, total number	9,000	243,000
EHPs In-Use, total households	<1,000	82,000
Solar DG, MW installed	950	1,400
Wind DG, MW installed	85	270

5.2 High DER Scenario Details

Hourly (i.e., 8760 hours/year) load forecasts were created for each DER type using these 2030 customer DER adoption assumptions to assess the distribution system impacts of each scenario. These hourly DER load forecasts were added to the baseline system load plus economic load growth and Energy Efficiency (EE) load forecasts using standard Company forecasting assumptions. Future hourly EV charging loads were developed based on residential (i.e., Level 1 and Level 2 at home) and commercial (i.e., Level 2 and DCFC at work or public) charging assumptions and using the U.S. Department of Energy's Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite.[15] Future EHP hourly data was modeled using assumptions for EHP configuration and performance (e.g., efficiency, cold-climate (cc) performance), availability of "backup" or supplemental heat sources, and end user preferences (e.g., thermostat set point temperatures). Annual hourly renewable generation was modeled using National Renewable Energy Laboratory's (NREL) PVWatts online calculator for solar DG and existing data for on-shore wind output for wind DG.[16] Key assumptions used in the High DER Scenario's 2030 forecast are summarized in Table 5.2.

[15] https://afdc.energy.gov/evi-pro-lite
[16] https://pvwatts.nrel.gov/

Table 5.2: 2030 Forecast Key Input Assumptions – High DER Scenario

Key Input Assumptions - High DER Scenario	Value
EV Fraction of On-Road Light Duty Vehicle Market	30%
EV Fraction of On-Road Medium Duty Vehicle Market	5%
EV Home L1 Charging Peak Demand, kW	2.0
EV Home L2 Charging Peak Demand, kW	3.6
EV Work/Public L2 Charging Peak Demand, kW	6.6
EV Work/Public DCFC Charging Peak Demand, kW	125
EHP Fraction of Delivered Fuel Space Heating Market (Residential, C&I)	65%
Change in Residential Heat Demand (Evaluation Year - 2030)	-10%
Fraction of Residential Customers using Non-ccEHP Heating in 2030	50%
Fraction of Residential Customers using Backup Heating Systems in 2030	50%
Residential EHP COP (annual average)	2.58
C&I EHP COP (annual average)	3.30
Wind DG Capacity Factor (annual average)	23%
Solar DG Capacity Factor (annual average)	18%
Solar DG Losses	14%
Solar DG Inverter Efficiency	96%

The contributions of each individual load forecast on the 2030 projected peak and minimum loads are presented in Figures 5.1 and 5.2 for the High DER Scenario. As can be seen, 2030 peak load is not expected to increase significantly even under the High DER Scenario. Unmanaged EV charging loads are expected to add over 200 MW of peak load, but this is offset by expected peak load reductions due to future Energy Efficiency (EE) measures. Managed EV charging using AMF-enabled advanced pricing (e.g., CPP, TVR), DR informed by grid modernization, or other means, is expected to have a smaller impact on peak load as EV customers are encouraged to charge during off-peak periods. Future electric heat pump (EHP) loads are not expected to increase peak load because the distribution system is projected to continue to be Summer peaking through at least 2030. Solar DG is not expected to reduce peak load due primarily to the lack of solar output during the late afternoon peak load period, which even today is between 5-6 pm. Wind DG could impact peak load, but due to its intermittency, it is likely that there will be days and hours where wind generation is very low and other loads are very high, like the illustrative load profile above. Conversely, Solar and Wind DG are expected to have a large impact on minimum load, particularly during light load periods in the Fall and Spring, as shown in Figure 5.2.

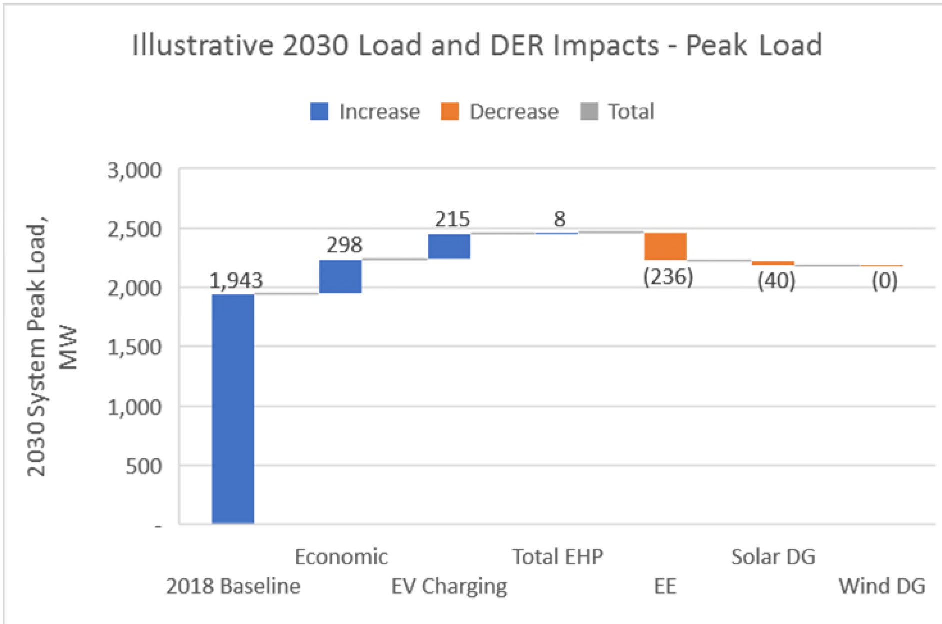


Figure 5.1: Illustrative 2030 Peak Load and DER Impacts under the High DER Scenario (July 22, 6 pm)

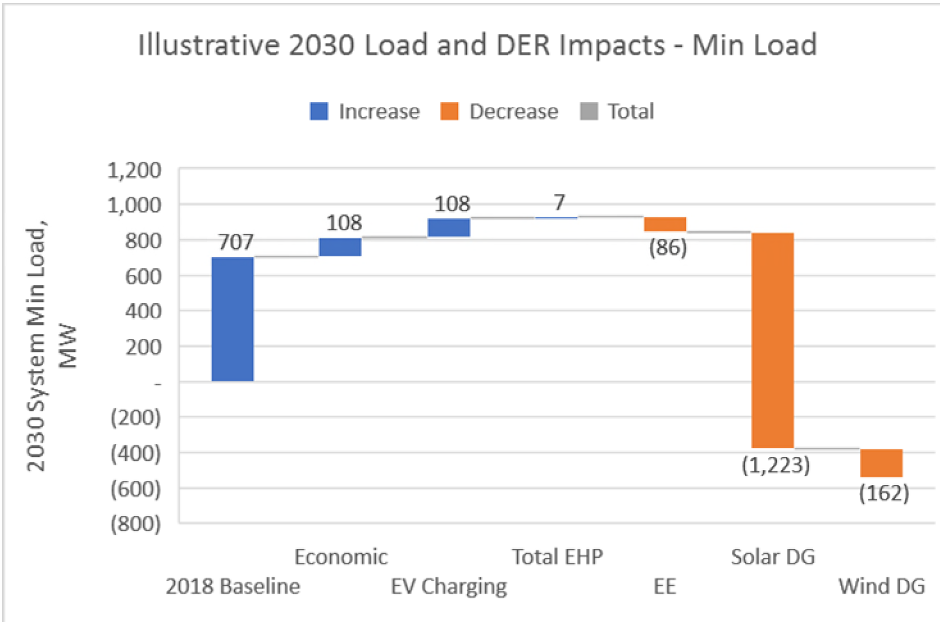
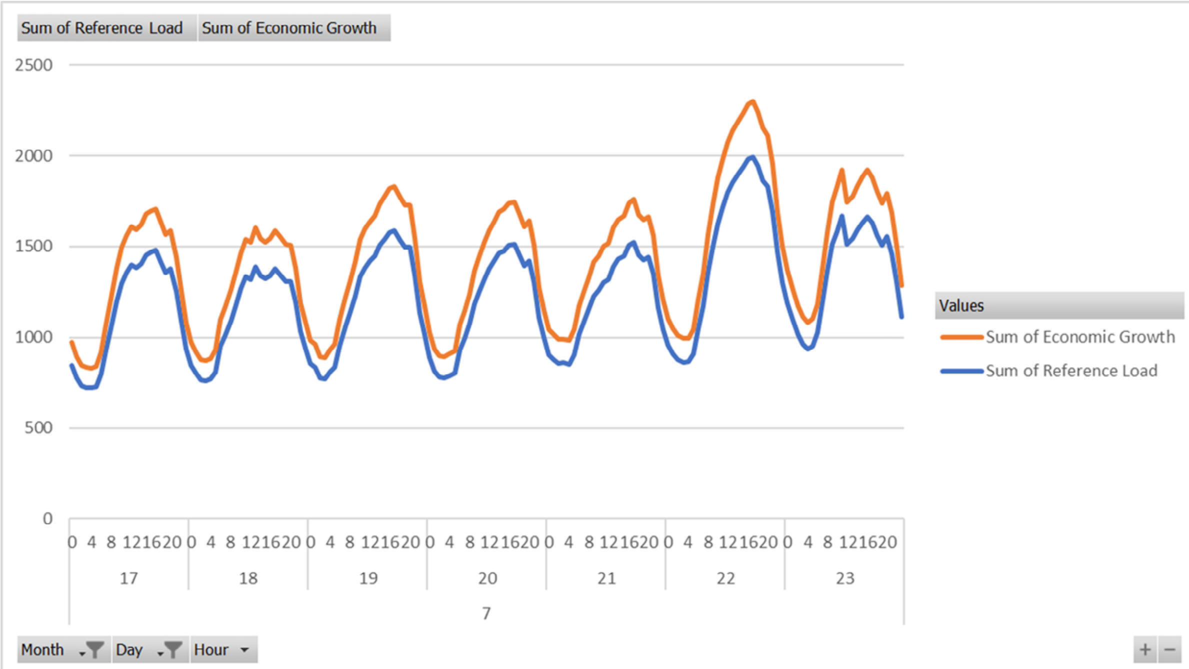


Figure 5.2: Illustrative 2030 Minimum Load and DER Impacts under the High DER Scenario (May 18, 11 am)

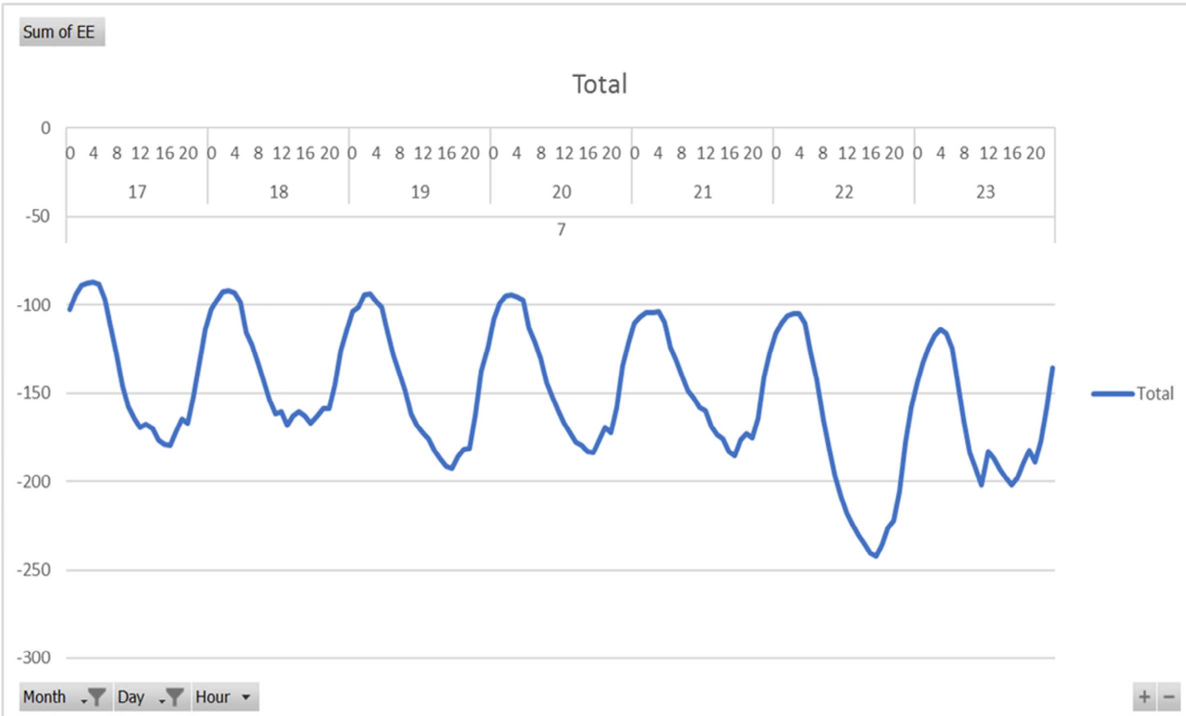
5.3 State-Level Load Cycles

The state level modeling described in *Section 6: State-Level Analysis Details* was developed to enable analysis of each forecasted load component independently. Each component was scaled per the various scenarios and added together to create a state-level load curve. Illustrative examples are presented below. Each figure shows the average daily state-level load cycle for each load component across the selected week within a particular month (i.e., 2 = February, 5 = May, 7 = July) projected for 2030 under the High DER Scenario.

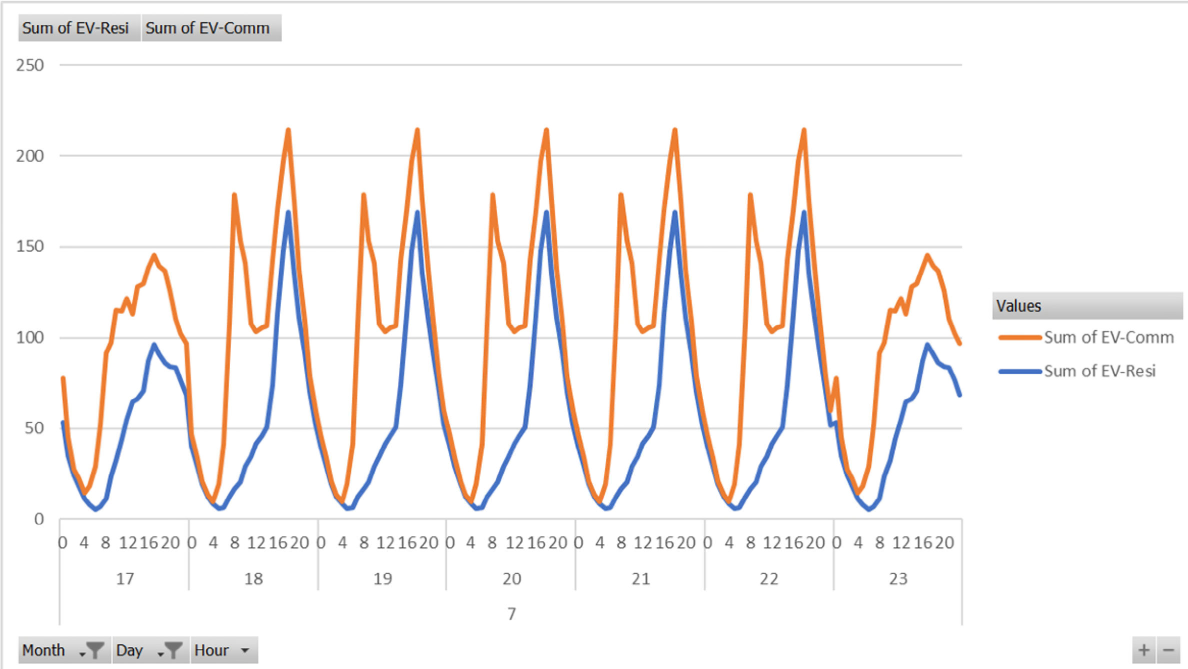
1) First, baseline (reference) load cycle information was combined with 2030 economic growth projections. In the chart below, the economic growth line shows the total load after economic growth has been added to the reference load.



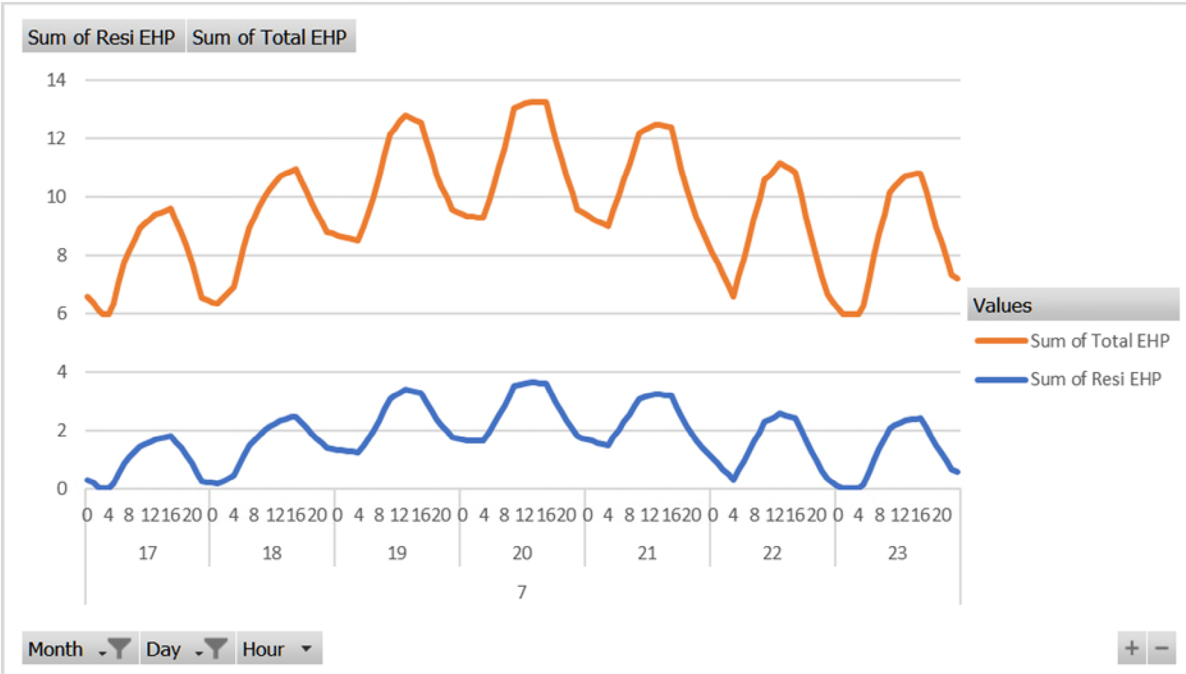
2) Energy efficiency impacts will be added as a negative load. The chart below shows the negative energy efficiency load that will be added to overall load.

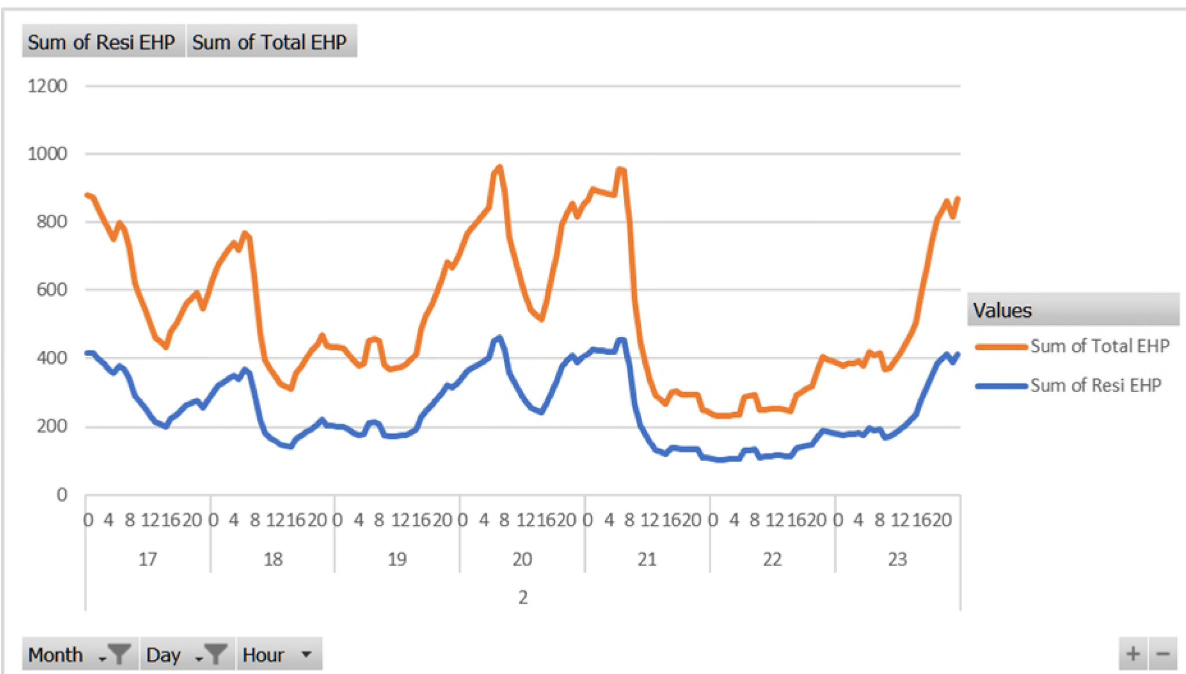


3) Unmanaged EV charging load will be added for both residential and commercial EV charging assumptions for 2030. The graph below shows load from residential EV charging and total load from all EV charging (residential and commercial). This curve demonstrates that unmanaged residential use is projected to occur in the late afternoon and early evening as many customers return home from work. Commercial use is projected to mainly occur during the early morning period as employees arrive at work.



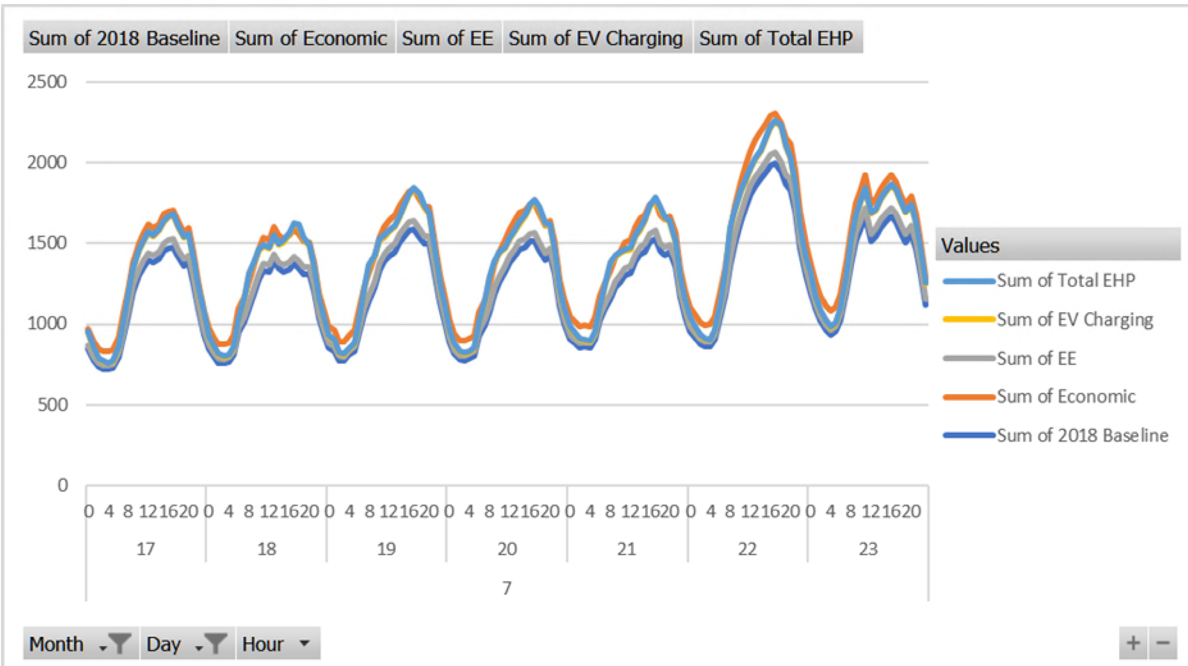
4) EHP loads will be added for both residential and commercial EHP assumptions for 2030. The graphs below show load from residential EHP demand and total EHP demand (residential and commercial) for projected summer (i.e., July) and winter (i.e., February) months. These curves demonstrate that EHP load is projected to be minimal during the non-heating summer months, but EHP load could be significant in the future if the system becomes winter peaking due to EHP adoption.



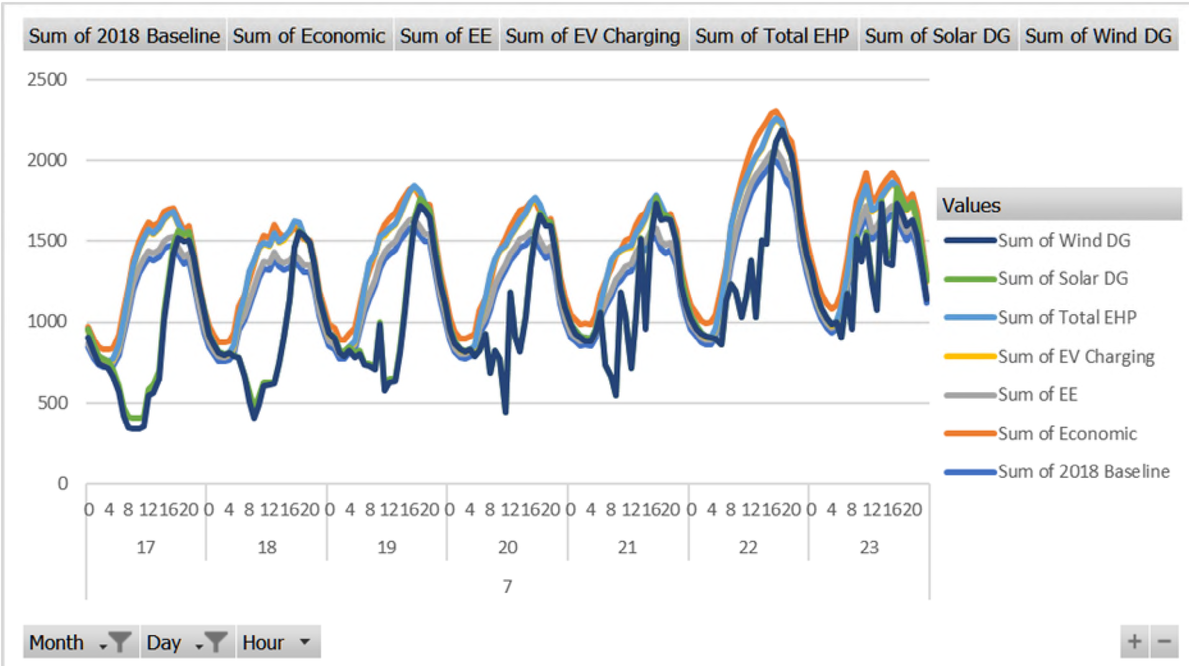


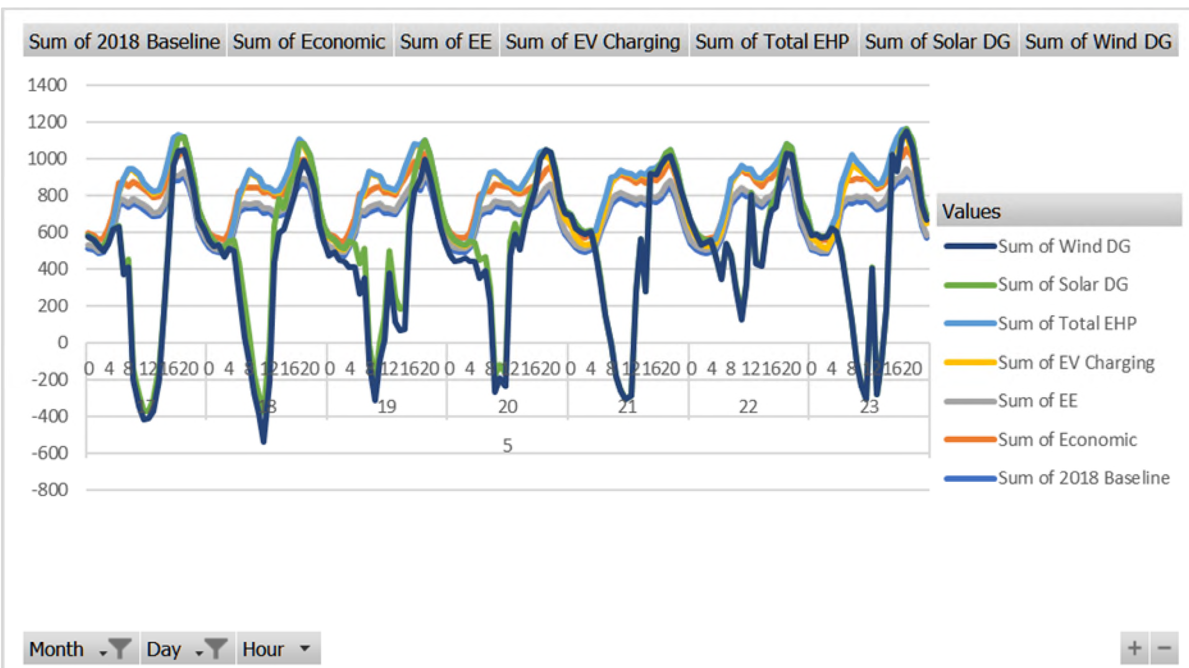
5) Each of the load components above were then added together to create a state-level load curve without DG: 2018 baseline (reference) load, plus economic growth, minus energy

efficiency, plus residential and commercial EV charging loads, plus residential and commercial EHP loads. The top load curve (Sum of Total EHP) represents the total load shape with all incremental additions and subtractions included except DG.



6) Finally, solar and on-shore wind DG were added as negative loads to create a total 2030 net load curve. The bottom load curve (Sum of Wind DG) represents the total load shape with all of the incremental additions and subtractions included. The graphs below show load from each individual DER for the forecasted 2030 peak load hour (i.e., July 22, 6 pm) and minimum load hour (i.e., May 18, 11 am). These graphs clearly show the unmanaged load versus generation mismatch projected by 2030 in the High DER Scenario.


Sum of 2018 Baseline
Sum of Economic
Sum of EE
Sum of EV Charging
Sum of Total EHP
Sum of Solar DG
Sum of Wind DG
2500
2000
1500
1000
500
0
0 4 8 121620 0 4 8 121620 0 4 8 121620 0 4 8 121620 0 4 8 121620 0 4 8 121620 0 4 8 121620
17
18
19
20
21
22
23
7
Values
Sum of Wind DG
Sum of Solar DG
Sum of Total EHP
Sum of EV Charging
Sum of EE
Sum of Economic
Sum of 2018 Baseline
Month
Day
Hour


Sum of 2018 Baseline
Sum of Economic
Sum of EE
Sum of EV Charging
Sum of Total EHP
Sum of Solar DG
Sum of Wind DG
1400
1200
1000
800
600
400
200
0
-200
-400
-600
-800
19
20
21
22
23
5
Values
Sum of Wind DG
Sum of Solar DG
Sum of Total EHP
Sum of EV Charging
Sum of EE
Sum of Economic
Sum of 2018 Baseline
Month
Day
Hour

6. State-Level Analysis Details

The High DER Scenario modeled as part of the state-level analysis resulted in a net load curve with several negative load periods due to the prevalence of renewable DG, particularly solar DG. This means that renewable DG would be in excess of load - or in other words, at times there would be more renewable DG available than Rhode Island customers needed at that time. Figure 6.1 shows the minimum, maximum, and average daily state-level load cycle across seasons projected for 2030 under the High DER Scenario. The figure shows the load bounds during a particular hour in a season within which the system is expected to perform. Across each day within a season, the system load could be at any point between the minimum and maximum lines. As can be seen in Figure 6.1, negative load occurs during some daytime hours when too much electricity is fed into the grid from renewable DG in relation to customer demand. Unless this negative load can be eliminated, high voltages and thermal congestion will result. Note that this load projection is based on the High DER Scenario forecast for Rhode Island and excludes off-shore wind generation or other transmission-connected wholesale generation.

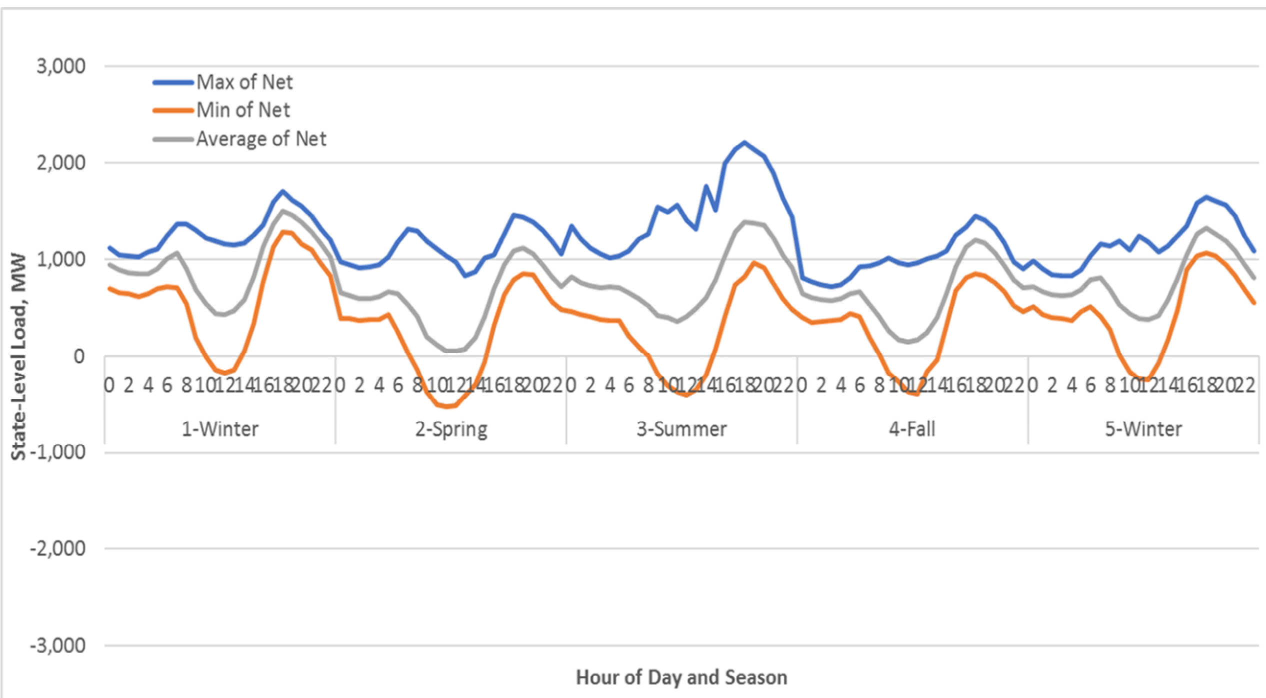


Figure 6.1: State-level load cycle across seasons projected for 2030 under the High DER Scenario

The GMP assumes DG curtailment, rather than upgrading the transmission system and exporting excess generation, is the most viable option for most excess renewable DG generation through 2030 under the High DER Scenario. Details are provided in *Section 5.4.2: State-Level Analysis* in the RI GMP Business Case document.

However, without grid modernization, the "Reference Case" distribution system, keeping the need for a safe and reliable electric system at the forefront, must be designed to curtail at all times when curtailment might be necessary and regardless of actual system performance. This is simply because there is currently no way to observe the actual system performance in a manner which allows a more refined curtailment option. So, the Future State Assessment Reference Case assumes the Company would need to curtail renewable DG anytime the estimated maximum seasonal DG output of the installed capacity was predicted to exceed the estimated seasonal minimum load, which is referred to here as "seasonal curtailment." As can be seen in Figure 6.2, this seasonal curtailment results in an average renewable DG curtailment of 20% of its annual energy output under the High DER Scenario by 2030.

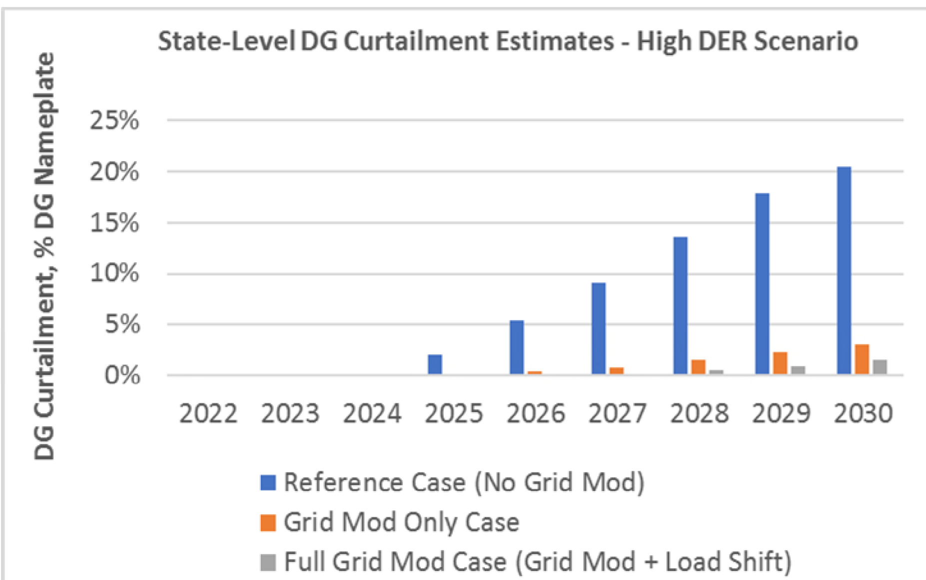


Figure 6.2: Renewable DG Curtailment Estimates – High DER Scenario

However, a grid with sufficient sensing and control would enable customer-owned DERs to be optimized for the benefit of the grid. In grid modernization cases (i.e., Grid Mod Only, Full Grid Mod), it is assumed that injections from customer-owned DG or energy storage can be managed such that the DG output would be curtailed only when necessary, resulting in an estimated curtailment of 3% of the DG annual energy output. With the addition of AMF in the Full Grid Mod Case, it is assumed customer loads can be shifted to periods of high DER output through advanced pricing (e.g., TVR) and customer load management programs that address distribution system needs such that DER curtailment would be reduced further.

The following assumptions were made in each case presented in Figure 6.2:

- Reference Case assumes inefficient seasonal DG curtailment based on worst-case scenario planning as described above

- Grid Mod Only Case (without AMF) assumes hourly DG curtailment is possible due to investments in sensing (i.e., Feeder Monitoring Sensors), processing (i.e., ADMS) and controls (i.e., Advanced Reclosers & Breakers, DERMS) that enable effective DER management (i.e., managing DER output to keep system parameters within predetermined limits)[17]

- Full Grid Mod Case (with AMF) assumes hourly DG curtailment is possible plus 10% load shifting[18] (i.e., shifting energy consumption between time periods to reduce energy costs and/or keep system parameters within predetermined limits) due to investments in AMF that enable advanced pricing and effective customer load management programs.[19]

The Sate-Level Analysis showed that under a Low DER Scenario, no curtailment was necessary due to limited deployment of renewable DG. However, the High DER Scenario, which had significant levels of renewable DG adoption, showed that up to 20% of DG's expected energy output could be curtailed by 2030 in the Reference Case. This level of curtailment not only reduces the energy output of the DG, which will make most Renewable DG projects would be uneconomic, but also impacts the emissions reduction of renewable DG. Grid modernization could be used to facilitate the state-level load to generation balance, thus reducing DG curtailment, maximizing renewable energy, maximizing load shifting, and maximizing emissions reductions across a number of DER adoption scenarios.

[17] Effective DER management will also likely require some combination of new DG Tariffs, Flexible Interconnection Standards, Distribution System Operating Requirements, and/or Smart Inverters. Details are provided in *Section 4.3: Complementary and Supporting Elements* in the RI GMP Business Case document.
[18] Load shifting assumes BE and other customer loads shift from peak hours to hours with high excess DG (e.g., middle of the day).
[19] Effective customer load management will likely require some combination of Time Varying Pricing, DR, EV, Energy Storage, and/or other customer programs. Details are provided in *Section 4.3: Complementary and Supporting Elements* in the RI GMP Business Case document.

7. Feeder-Level Analysis Details

In depth feeder analysis was conducted for this GMP applying traditional planning concepts in new ways. Traditional planning studies review a number of system variables, such as voltage, current, and fault current, across a feeder's topology. This GMP further analyzed these variables across the hours of the year.

7.1 Representative Feeder Selection

In consideration of the substantial increase in forecasted data over traditional study efforts, it would be impractical to study the entire distribution system within Rhode Island. Instead, representative feeders were identified, and six feeders were selected:

- Chopmist 34F1 - Rural, Sub-transmission sourced, Existing DG = 8.1 MW
- Chopmist 34F2 - Rural, Sub-transmission sourced, Existing DG = 0.2 MW
- Chopmist 34F3 - Rural, Sub-transmission sourced, Existing DG = 1.3 MW
- Old Baptist Road 46F4 - Rural, Coastal, Existing DG = 4.0 MW
- Kenyon 68F3 - Rural, Coastal, Existing DG = 0.0 MW
- Point Street 76F2 – Urban, Existing DG = 0.4 MW

The circuit group contains a mix of types, sources, and DG penetration sufficient to conduct detailed analysis and draw reasonable state-wide conclusions. The Chopmist feeder grouping also added an ability to test the subtransmission system and feeder transfers.

With the study bounded by practical considerations, a detailed and comprehensive BCA approach could be undertaken for the GMP including:

- Scenario Evaluation used to understand the range of issues Rhode Island will likely encounter on the distribution system through 2030;
- State-Level Modeling (timing of generation to load) used for state-level curtailment analysis to quantify benefits of Active Power Control;
- Feeder-Level Modeling (ability of generation to get to load) used for feeder-level distribution system infrastructure requirements to quantify benefits of Monitoring & Control and Load Shifting;
- BCA used to explain areas of value to regulators using Rhode Island's Docket 4600 framework; benefits and costs were quantified to the greatest extent possible and explained qualitatively when not possible to quantify; and
- Sensitivity Analysis used to assess project risk on alternative futures by measuring the impact of uncertainties in key BCA inputs and assumptions.

7.2 Modeling Approach and Assumptions

A rigorous modeling approach was used to organize the study. First, six representative feeders were selected based on the approach outlined in *Section 9.8: Representative Feeder Selection* above. Next, sets of load curves were developed in an identical fashion to steps 1 through 5 described in *Section 5.3: State-Level Load Cycles*. These load curves were loaded into the distribution analysis software in groups of 3 for each scenario – 1) with EHP loads; 2) with EHP and EV charging loads; and 3) with EHP and EV charging loads and with a 10% peak load shift period. Renewable DG was not included in the load curve and instead modeled directly. Starting with the state-wide projected DG capacity (megawatts), an allocation method based on customer count was used to assign rationed portions to the circuits under study. Table 7.1 shows the DG feeder allocations.

Table 7.1: DG Allocation for Low DER and High DER Scenarios

Location	Feeder	Type	Low DER Scenario	High DER Scenario
Scituate, Chopmist	34F1	Rural, Sub-T sourced	2.4 MW	12.0 MW
Scituate, Chopmist	34F2	Rural, Sub-T sourced	2.4 MW	9.6 MW
Scituate, Chopmist	34F3	Rural, Sub-T sourced	0.6 MW	2.8 MW
North Kingstown, Old Baptist Road	46F4	Rural, Coastal	2.4 MW	12.0 MW
Richmond, Kenyon	68F3	Rural, Coastal	2.4 MW	12.0 MW
Providence, Point Street	76F2	Urban	1.2 MW	6.4 MW

A project manager tool was used to categorize model additions and adjustments. The DG additions were setup by scenario and by year. Similarly, the solutions were also setup in the project manager tool. This allows for any DG scenario to be turned on or off by year and any solution set turned on or off as needed.

7.3 Summary of Needs and Opportunities

The summary of issues can be divided into three main categories: 1) overvoltage due to DG penetration during light load periods; 2) loading issues mainly due to EV charging additional loads during peak periods; and 3) protection coordination issues including arc flash analysis. Figures 7.1-1.5 copied from the distribution analysis tool highlight the issues found. Red colors indicate low voltage and overloads. Orange and brown colors indicate over voltage. Other colors (e.g., blue, green, and black) are acceptable voltage and loading levels.

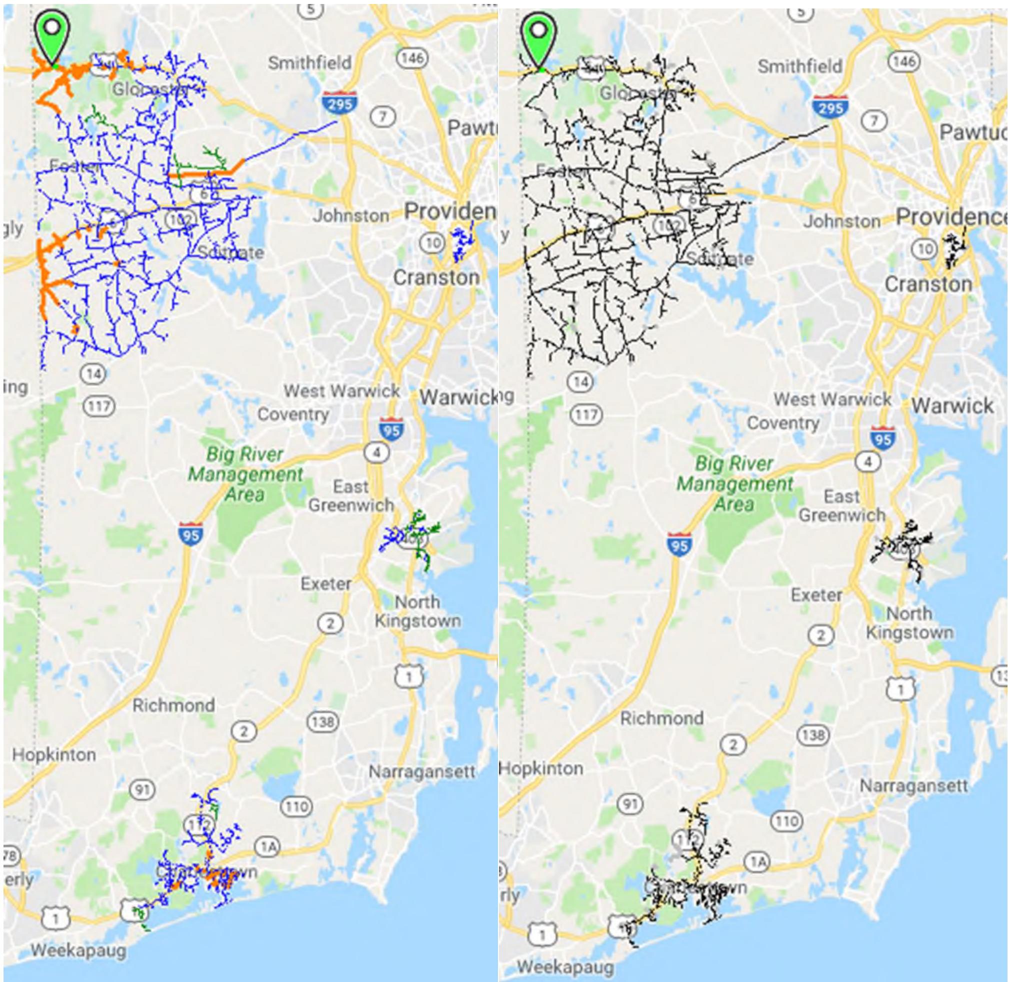


Figure 7.1: Low DER Scenario – Voltage and Loading Issues – Light Load Test

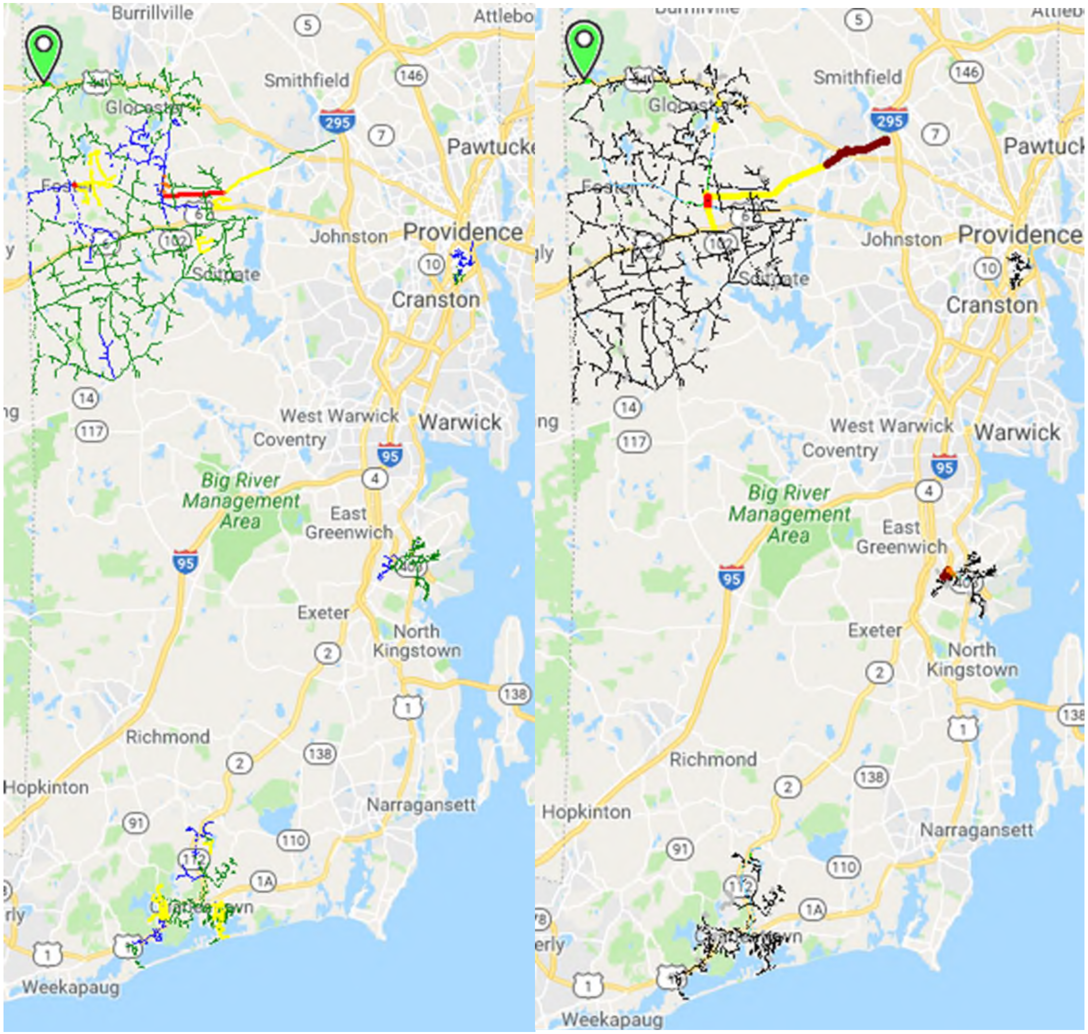


Figure 7.2: Low DER Scenario – Voltage and Loading Issues – Peak Load Test

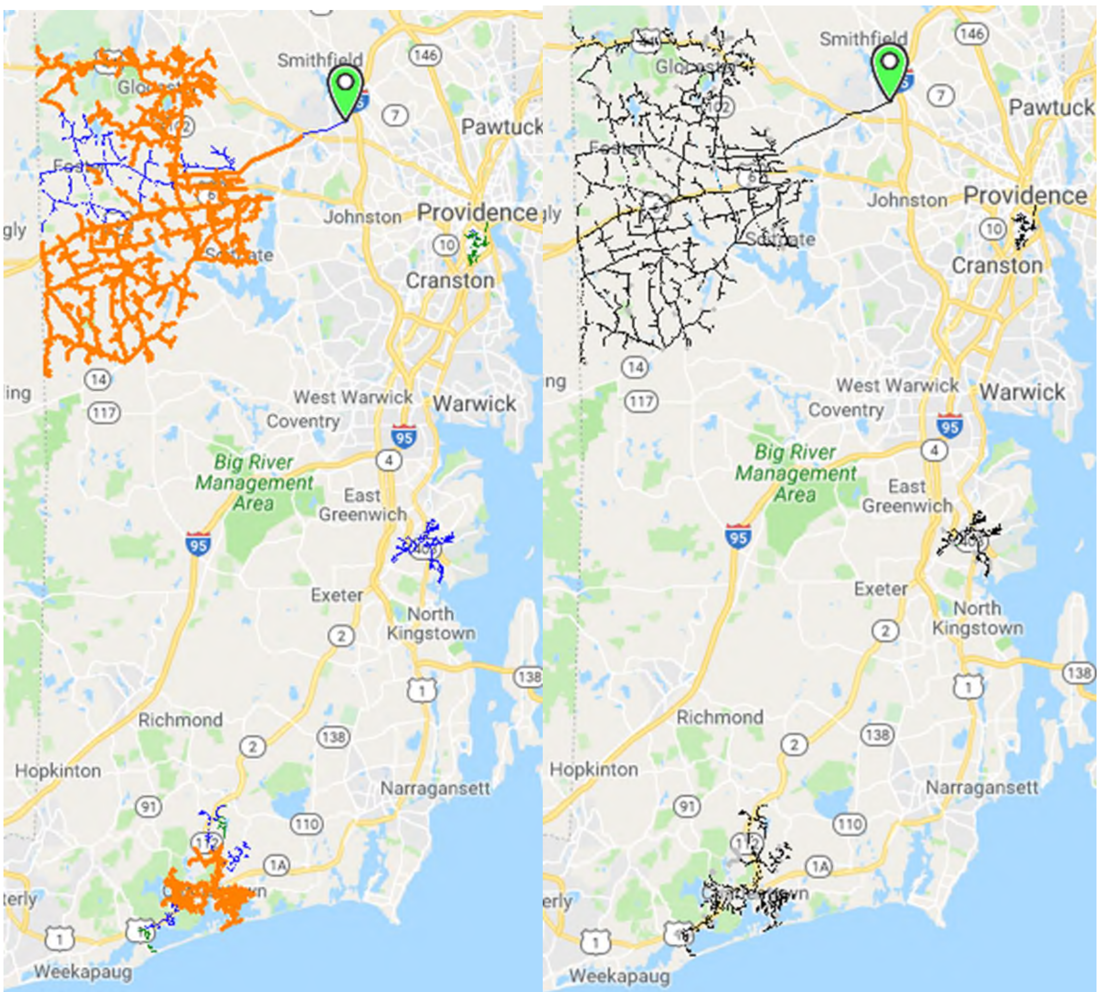


Figure 7.3: High DER Scenario – Voltage and Loading Issues – Light Load Test

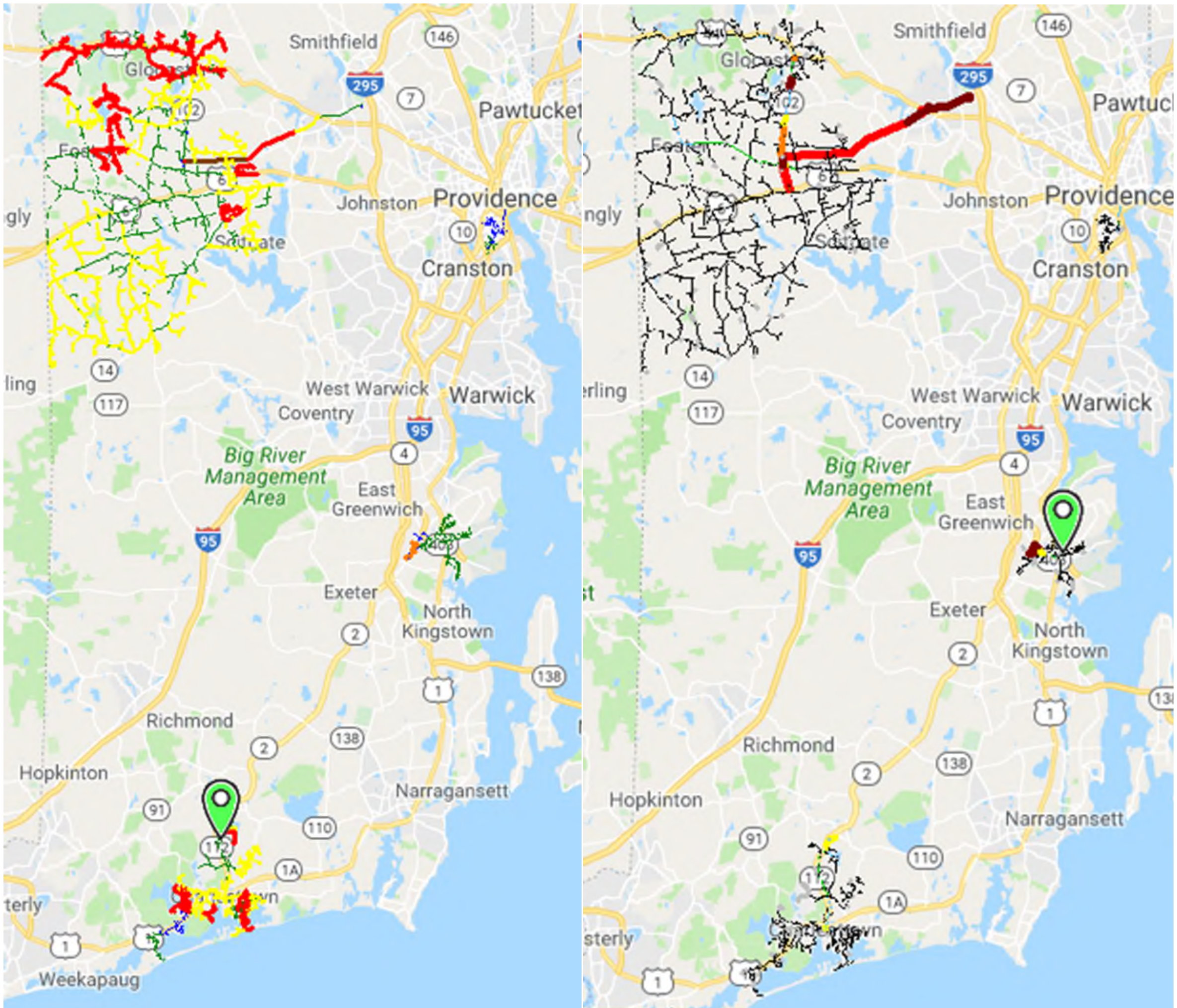


Figure 7.4: High DER Scenario – Voltage and Loading Issues – Peak Load Test

As can be seen above, both scenarios have some overvoltage exposure. The Low DER Scenario has limited overvoltage issues primarily on subtransmission sourced circuits. The High DER Scenario has wide-spread subtransmission sourced overvoltage issues with growing issues on the remaining circuits. Of note, the 76F2 feeder (i.e., Providence, Point Street) has limited to no voltage issues across all scenarios due to its proximity to transmission connected generation in downtown Providence. This highlights the risk to feeders with high source impedance such as subtransmission sourced circuits. The loading issues are mainly centered on the subtransmission circuit and the feeder getaways.

With new sources of generation come new sources of fault current, which can desensitize protection systems as can be seen by the increase clearing time shown in Table 7.2. This can also impact Personal Protective Equipment (PPE) requirements of the workers. Although the standard distribution PPE category is 8-Calorie clothing, the indication that DG can increase the required PPE level is of concern. Figure 7.5 copied from the distribution analysis tool highlight the issues found. Orange and yellow colors indicate growing protection and arc flash concerns.

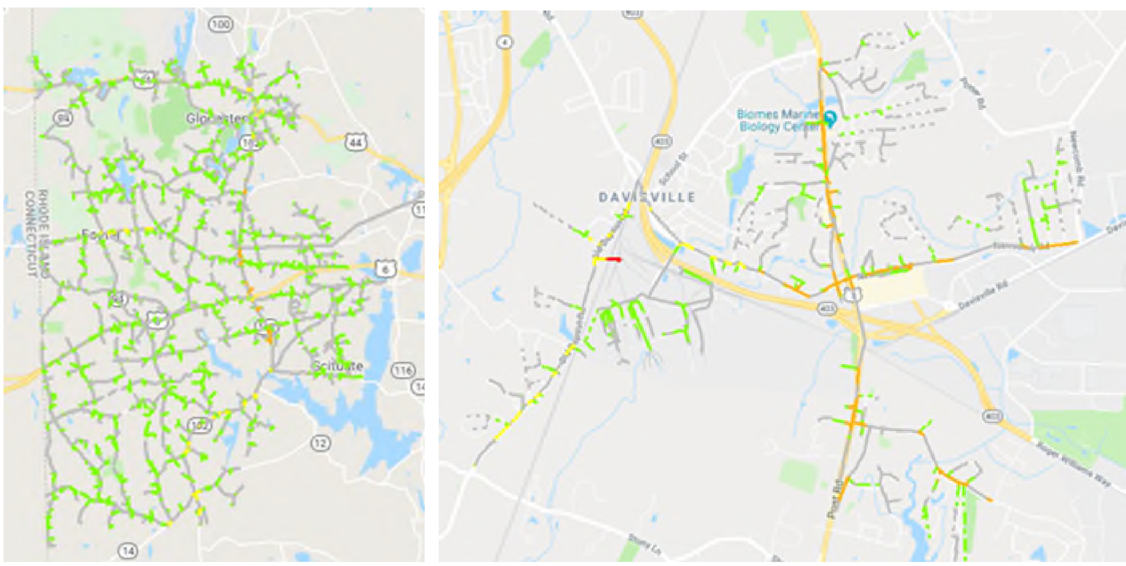


Figure 7.5: High DER Scenario – Protection Coordination & Arc Flash Analysis

Table 7.2: Fault Current Clearing Times and PPE Requirements

Case	Circuit	Bolted Fault (kA)	I (arc) seen by device (kA)	Protective Device Type	Clearing Time (ms)	Incident Energy (cal/cm²)	Cal System
Without DG	34F1	1.854	1.849	Recloser	185	0.342	2
With DG	34F1	2.063	1.805	Recloser	190	0.391	2
With DG	34F1	2.063	0.151	Fuse	2000	4.112	8
Without DG	34F3	0.774	0.768	Relay-Controlled Breaker	1035	0.792	2
With DG	34F3	1.099	0.544	Relay-Controlled Breaker	2000	2.177	4
Without DG	46F4	2.288	1.849	Relay-Controlled Breaker	1090	2.489	4
With DG	46F4	2.611	1.594	Relay-Controlled Breaker	1279	3.337	4
With DG	46F4	2.611	0.272	Fuse	2000	5.220	8

7.4 Avoided Distribution Infrastructure Assessment

Grid modernization investments will enable improvements in load optimization due to the ability of the system operator to autonomously or remotely control power flows on the distribution system, either by rearranging the distribution feeders or optimizing power output from renewable DERs, rather than investing in traditional "wires" solutions (e.g., reconductoring, substation upgrades) to relieve thermal or voltage constraints due to DER adoption. Table 7.3 summarizes the primary solutions necessary for both the High and Low DER scenarios to highlight how grid modernization can avoid major infrastructure investments. Note that in addition to these "primary solutions", additional foundational investments in GIS Data Enhancements, Underlying IT Infrastructure, Cybersecurity, and Telecommunications are expected to be necessary.

Table 7.3: Primary Solution Set for Each GMP Case and Scenario

Analysis Category	Low DER Scenario		High DER Scenario	
	Reference Case	Grid Mod Cases	Reference Case	Grid Mod Cases
Overvoltage	Limited deployment of Advanced Capacitors, upgrading LTC controls	Full deployment of Advanced Capacitors, AMF (Full Grid Mod Case only)	Full deployment of Advanced Capacitors & Regulators	Full deployment of Feeder Monitoring Sensors, Advanced Capacitors & Regulators, ADMS (centralized control), DERMS, AMF (Full Grid Mod Case only)
Loading	Limited distribution reconductoring	Feeder Monitoring Sensors, Advanced Reclosers, ADMS, AMF (Full Grid Mod Case only)	New sub-transmission line and 2 new circuits	Feeder Monitoring Sensors, Advanced Reclosers, ADMS, DERMS, AMF (Full Grid Mod Case only)
Protection Coordination & Arc Flash	No identified solution (sub-transmission sourced circuits at risk)	Sub-transmission sourced circuits at risk	No identified solution (all circuits at risk)	Advanced Reclosers, ADMS-based Protection & Arc Flash App

As can be seen from the table above, grid modernization solutions can be used to solve multiple issues due to increasing DER adoption. For example, ADMS and DERMS can be used to resolve both Overvoltage and Loading issues, and Advanced Reclosers along with an ADMS-based Protection & Arc Flash Application can be used to resolve both Loading and Protection issues in the High DER Scenario. The Reference Case relies more heavily on expensive reconductoring to solve Loading issues, while autonomously controlled Advanced Capacitors are installed now and would be installed in any Reference Case to resolve Overvoltage issues. The Reference Cases does not leverage the loading related investments to assist with voltage performance or central control of the devices via an ADMS.

The GMP BCA represents the difference in the costs between the Reference Case and the Grid Mod Cases as an Avoided D-System Infrastructure Cost benefit. The major avoided cost is mainly in the loading category. As can be seen in the table above, grid modernization can avoid new sub-transmission lines and new circuits through DER output optimization and remote circuit reconfiguration in a Grid Mod Only Case and additional 10% load shifting as a sensitivity analysis in the Full Grid Mod Case.20 In addition to these Avoided D-System Infrastructure Cost benefits, investments in Advanced Field Devices and other grid modernization solutions also contribute to significant customer benefits related energy savings (e.g., VVO/CVR), reliability improvements (e.g., FLISR), and avoided bulk energy purchases (e.g., ADMS, DERMS).

7.5 DER Impact Assessment

The Company's evaluation of grid modernization solutions required to meet growing DER loads is primarily driven by the quantity of DER expected to be adopted in the future. Therefore, Company evaluated a range of DER adoption levels and the results are presented throughout the RI GMP Business Case document as the Low and High DER scenario results. However, there are additional factors that are likely to have a smaller impact on the exact timing of deployment of Advanced Field Devices and Optimizing Applications. In particular, the type of DER adopted, whether DG (i.e., solar or wind) or beneficial electrification (i.e., EV or EHP), and the size of the DG adopted, whether Large DG (>1 MW) or Small DG (<1 MW). Therefore, the Company evaluated two additional customer DER adoption scenarios and two DG size options for consideration under the Feeder-Level and State-Level analyses. As can be seen, there is significant overlap among all DER scenarios and DG options evaluated.

Additional DER Scenarios

The Company evaluated two additional possible customer DER adoption scenario to evaluate possible impact on the timing of deployment of Advanced Field Devices and Optimizing Applications:

- High Customer DG Adoption (High DG) Scenario – High adoption of renewable DG based on achieving the State's 80x50 Goal, but assuming a more conservative adoption of EV and EHP.

- High Customer BE Adoption (High BE) Scenario – High adoption of EV and EHP based on achieving the State's 80x50 Goal, but assuming a more conservative adoption of renewable DG; EV and EHP adoption assumptions are consistent with National Grid's Northeast Pathways Study.

These scenarios are defined by their 2030 customer DER adoption assumptions summarized in Table 7.4 along with the High DER and Low DER scenarios for comparison. The DER assumptions are based on the Company's review of industry forecasts and input from internal

[20] 10% load shifting is assumed due to investments in AMF that enable customer load Management programs that addressed distribution system needs through Time Varying Pricing, DR, EV, Energy Storage, and/or other customer programs.

subject matter experts. Details are also presented in the *Section 3.2: Future State Scenarios* of the RI GMP Business Case document.

Table 7.4: 2030 Customer DER Adoption Assumptions for Future State Scenarios

2030 Future State Scenario Assumptions	1) Low DER	2) High DER	3) High DG	4) High BE
EVs On-Road, total number	9,000	243,000	80,000	400,000
EHPs In-Use, total households	<1,000	82,000	30,000	110,000
Solar DG, MW installed	950	1,400	2,100	800
Wind DG, MW installed	85	270	270	270

High DG Scenario

If primarily solar DG is adopted in the future and adoption of BE is more limited, feeder-level analysis shows there will be more high voltage issues during daytime off-peak periods that will require the following grid modernization investments:

- Feeder Monitoring Sensors
- Advanced Capacitors & Regulators
- ADMS (centralized control)
- VVO/CVR
- DERMS
- AMF (Full Grid Mod Case only)

In additional, State-Level Analysis shows there will be significant negative load periods during daytime off-peak periods under the High DG Scenario, which will require granular monitoring and control to prevent widespread seasonal DG curtailment. These capabilities will require the following grid modernization investments:

- Feeder Monitoring Sensors
- Advanced Reclosers & Breakers
- ADMS
- DERMS
- AMF-based TVR or other DG management solutions (Full Grid Mod Case only)

High BE Scenario

If primarily BE is adopted in the future and adoption of DG is more limited, feeder-level analysis shows there will be more low voltage and overloading issues during late afternoon/early evening peak periods that will require the following grid modernization investments:

- Feeder Monitoring Sensors
- Advanced Capacitors & Regulators
- Advanced Reclosers & Breakers
- ADMS
- VVO/CVR
- DERMS
- Protection & Arc Flash App
- AMF-based TVR or other DG management solutions (Full Grid Mod Case only)

State-Level Analysis shows there will not be significant negative load periods during daytime off-peak periods under the High BE Scenario.

Additional DG Size Options

The Company evaluated two customer DG size options to bookend the range of possible impact on the timing of deployment of Advanced Field Devices and Optimizing Applications:

- Small DG Option – Assumes residential DG deployments only
- Large DG Option – Assumes one large 10 MW solar DG and one large 3 MW wind DG per feeder

Results of the Feeder-Level Analysis showed there is significant overlap among all options and scenarios evaluated. If primarily Large DG is adopted, feeder-level analysis shows there will be additional loading issues and protection issues under the High DER scenario that will require the following additional grid modernization investments in Advanced Reclosers & Breakers and Protection & Arc Flash Application. In the “Large DG” options for both the Low and High DER scenarios, it might be possible to avoid investments in AMF-based TVR or other DG management solutions. However, AMF-based TVR provides other important benefits to customers described in the GMP Business Case and Updated AMF Business Case documents.

If primarily Small DG is adopted, loading and protection issues are likely to be less significant, but voltage issues will still be significant, and DG curtailment will require the following additional investments in DERMS or AMF-based DG management solutions. In the “Small DG” option for the Low DER scenario, it might be possible to avoid some investments in Advanced Reclosers & Breakers, and the Protection & Arc Flash App. However, these investments provide other important reliability and avoided DG curtailment benefits described in the RI GMP Business Case. As described in *Section 3: Risk Management Approach* in the GMP Business Case document, the Company will evaluate specific needs on an annual basis using load forecasts that are informed by customer DER adoption trends. If trends and forecasts point to a "Small DG" future, adjustments would be made to the proposed grid modernization investments in the annual ISR and future rate case filings.

7.6 Advanced Field Device Deployment

While the actual deployment of Advanced Field Devices will be determined based on area studies conducted as part of annual ISR plans, the Feeder-Level Analysis has identified a deployment priority for substations and feeders in the State, as summarized below.

1. Subtransmission sourced 15kV substations – about 26 substations, 104 feeders, 25-30% of the system
    a. Analysis demonstrated that sub-transmission sourced stations/feeders have the highest risk for voltage and loading compliance violations due to high source impedance, which means fault current and voltage impacts of DER are greater
    b. Subtransmission sourced 15kV feeders are often located in Western and remote parts of the State where limited transmission infrastructure exists – this also happens to be where DG projects are being interconnected due to land availability

2. Transmission sourced 15kV substations – additional 30 stations (56 total), additional 120 feeders (224 total), additional 30%-35% of the system (55%-65% total)
    a. Analysis shows that transmission sourced 15kV stations have somewhat lower risk for voltage and loading compliance violations than sub-transmission sourced substations at lower DER adoption levels
    b. Transmission sourced 15kV feeders are also in areas where DG projects are being interconnected due to land availability

3. All remaining substations – additional 36 stations (92 total), additional 144 feeders (368 total), additional 35-45% of the system (about 100% total)
    a. Although some substations and feeders have a lower risk for voltage and loading compliance violations, at high DER adoption levels, all substations and feeders be impacted
    b. Under high DER adoption scenarios, DER penetrations will not be limited to remote areas of the state
    c. Note that transmission sourced 4kV substations are typically older parts of the electric system in urban areas with less available land, and loading limits are reached with lesser amounts of DER, which typically results in higher interconnection costs

8. Functionality Definitions

Unless otherwise noted, most definitions below are based on recent work being progressed by public and private partners to update the DOE Next-Generation Distribution System Platform (DSPx) Modern Distribution Grid guidelines, which the Company has contributed to over the last few years.[21]

Customer Information: Access to customer energy use data by customers and customer-designated entities, complying with privacy and confidentiality requirements and utilizing standard data formats and data exchange protocols. This may include appropriate access to historical and real-time energy consumption, billing related information, service quality data, as well as outage information collected by distribution services provider and/or retail energy services provider. Example solutions: AMF (e.g., GBC, CEMP, integration with in-home technologies).

Advanced Pricing: Pricing that can change in response to various factors such as time, variable peak, location, and proximity to load, resource, supply conditions, system conditions, incentives/penalties, and "controllability" of supply and demand resources. Example solutions: AMF (e.g., Interval Energy Usage Data).

Remote Metering: Advanced meters and telecommunications network capable of remotely capturing and transmitting customer energy usage data and remotely connecting and disconnecting electric service in near real-time. This functionality results in operational efficiencies from eliminating meter reading, investigations and visits to connect and disconnect service. Example solutions: AMF (e.g., remote meter reading, remote connect & disconnect).

Distribution System Information Sharing: Distribution system data sharing that supports intended use cases for DER integration with mutual sharing between customers, third parties and utilities, complying with privacy and confidentially requirements, to promote customer choice and integration of DERs into planning and operations. This includes appropriate access to historical system and forecast planning data (e.g., load profiles, peak-demand, hosting capacity, beneficial DER locations, interconnection queue, voltage, and thermal limits) in standardized formats. Example solutions: System Data Portal.

Observability (Monitoring & Sensing): Ability to provide actionable information on the operating state and condition of the distribution grid, grid and DER assets, and environmental

[21] DOE's Modern Grid Initiative works with public and private partners to develop the concepts, tools, and technologies needed to measure, analyze, predict, protect, and control the grid of the future. Multi-volume guidance documents are available on the Pacific Northwest Laboratory's website, https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

conditions necessary to safely, securely, and reliably operate the electric system. It includes visibility, which is the ability to obtain timely sensing and measurement data. Example solutions: Feeder Monitoring Sensors, Advanced Capacitors & Regulators, Advanced Reclosers & Breakers, AMF (Load & Voltage Data).

Power Quality Management: Process of ensuring proper power form, including mitigating voltage transients and waveform distortions, such as voltage sags, surges, and harmonic distortion as well as momentary outages.[i] Example solutions: Advanced Capacitors & Regulators, ADMS (Voltage Control), VVO/CVR platforms, AMF (Load & Voltage Data).

Distribution Grid Control: Ability to manage distribution power flows while maintaining distribution operational parameters (e.g., voltage, reactive power, and power quality) within specific operating ranges through the application of performance criteria to the dynamic management of grid devices and DER in response to changes in load and injected power flows, and system disturbances.[ii] Example solutions: Advanced Reclosers & Breakers, ADMS-based Protection & Arc Flash Application, DSCADA, AMF (Load & Voltage Data).

Distribution System Representation (Network Models): Topological model of the physical distribution system, and customer and DER connectivity (including asset characteristics) that reflects dynamic changes to the state of the system.[iii] Example solutions: GIS Data Enhancements.

Grid Optimization: Analytical functionality integrated with decision support systems and/or operational controls to optimize the performance of grid reliability, resilience, efficiency, hosting capacity, as well as related work and resource management.[iv] Example solutions: ADMS (System Monitoring, State Estimating, Switching), AMF (Load & Voltage Data).

Operational Analysis & Forecasting: Operational analysis involves the dynamic assessment of the state of the distribution system to inform real-time contingency planning, system operations including switching plans, and operational controls and DER dispatch. Operational forecasting uses a combination of measured data and analytics to develop short term (minutes, hours, days) projections of loads and resources for operational scheduling, management, and optimization purposes. Example solutions: ADMS (Visualization, Simulation and Analysis).

Operational Information Management: Operational data recording, processing, and storage used to support operational businesses functions and related processes. Example solutions: Distribution PI Historian, Underlying IT Infrastructure (Enterprise Integration Platform, Data Management, Corporate PI Historian).

Cyber Security: Protection of computer systems from theft or damage to the hardware, software or the information on them, as well as from disruption or misdirection of the services they provide. It includes controlling physical access to the hardware, as well as protecting against harm that may come via network access, data and code injection, and due to malpractice by operators, whether intentional, accidental or due to deviation from secure procedures. [v,vi] Example solutions: Appropriate Cyber Services.

Operational Telecommunications: Communication protocols, technologies, and assets that are present between operating centers and substations, and extends into the field to connect grid sensors and controllable grid devices (e.g., switches, capacitor banks, protective devices, etc.) on local feeders. The performance and security requirements of operational communications networks for mission-critical uses, such as the electric grid, are significantly greater than public networks, internet service, and standard enterprise networks. Operational telecommunications are intended to maintain highly reliable connectivity under both normal and degraded system operating conditions (e.g., electrical noise, equipment failure, and physical attacks).[vii] However, no communication system is invulnerable to failure, making it a key modern grid design requirement for systems to operate safely and reliably in the event of loss of telecommunication infrastructure connectivity. Example solutions: OpTel Strategy, Network Management.

Reliability Management: Processes and systems that enable distribution operators to discover, locate, and resolve power outages in an informed, orderly, efficient, and timely manner. The reliability management function involves operations to capture and analyze fault current indicator, meter-level outage information, and real-time customer provided information on outages to improve the identification and isolation of electric distribution system faults, as well as service restoration of unaffected segments.[viii] Example solutions: ADMS-based FLISR Application, AMF (Automated Outage & Restoration Notification, Granular Fault Location).

DER Operational Control: Real-time direct or indirect control or coordination of DERs through pricing and/or engineering signals, in order to optimize network operations and to maintain the reliability and resilience of the system.[ix] Example solutions: DERMS, AMF (Remote Interval Meter Reading, Load & Voltage Data, Tier 3 Operational Telecommunications).

9. OpTel Strategy Details

The Company is still developing definitive OpTel Strategy implementation plans, and it is currently evaluating long-term plans to deploy private fiber and/or microwave technologies into substations and other facilities to support currently deployed assets as well as technologies. To realize the desired grid modernization functionalities requires integrating multiple devices across the grid, such as VVO/CVR, EV charging, DG, and Advanced Field Devices. These additions to the telecommunications platform results in increased data transfer that will require greater bandwidth and an appropriate latency to deliver the desired grid modernization functionalities. As the scale and importance of the telecommunications network expands, the Company believe important performance and efficiency gains may be realized through increased private ownership and control.

Tier 1 & Tier 2 Network Modernization

The Company is considering the following key project objectives within its Tier 1 and 2 OpTel Strategy review:

- Enable increased connectivity to substations, operations centers and critical/key facilities through network equipment upgrades at these locations
- Provide diversity and expansion to the DSCADA system allowing for the near real-time evaluation, analysis, and operation of the grid
- Eliminate leased analog circuits that are being retired by the carrier

The starting point of upgrading the communications network to support grid modernization lies within Tier 1 and 2. This core network piece acts as the foundation upon which other OpTel initiatives may be added such as Tier 3 wireless access for field devices at the network edge. Obsolescent networking gear needs to be upgraded with the most current technology in order to provide increased network reliability, control, security, and performance. It is also the easiest and most economical way to begin privatization by way of simply owning the business-critical networking equipment on premise at substations and other key facilities. In addition to using private fiber and microwave to connect these strategic network nodes, commercial telecommunications service providers may also provide the physical fiber between endpoints. However, the Company will always be able to manage and control this important backbone of the communications network by owning the active electronics. With private ownership of network equipment, a more competitive, vendor-neutral environment exists to partner with the best service providers at the lowest price. Over time, more private fiber will also be deployed, truly reducing reliance on public carriers and overall cost of network backhaul.

The primary equipment at the heart of network transport is called a data multiplexer (DMX). Currently, the Company's existing DMX solution has reached end-of-life and the standard technical support will be discontinued at the end of 2021. In preparation for this event, the Company has begun the evaluation and assessment of the replacement technology, and has down-selected three of nine companies in the final rounds of testing and contract negotiation. The leading technology is Multi-Protocol Label Switching (MPLS) which is protocol-independent and highly scalable, allowing for any type of transport medium, using any network protocol. True network convergence capable of combining many older legacy technologies may be achieved with MPLS.

The preliminary design for Rhode Island has also begun where 12 key nodes have been identified to make up the core network, including 10 transmission substations, 1 distribution substation, and 1 microwave tower site. The Rhode Island network represents a subset of the greater 150 DMX sites located throughout the Company's three-state service area. The next steps will be to examine the benefits and costs of leasing from commercial carriers, installing private fiber, or adding microwave links. While the majority of the network backbone resides at the transmission substations, it is important to note that all proposed grid modernization OpTel initiatives involving distribution substations and Tier 3 Advanced Field Devices greatly depend and interconnect with this core network.

In order to enable the GMP initiatives proposed, the existing rudimentary communications must first be upgraded to current technologies that support the new requirements for increased network performance, security, reliability, and control. Nearly half of the SCADA communications at substations is analog and only 6 of the 42 transmission substations have fiber connectivity. Figure 9.1 details the type and distribution of the various network connectivity for Tier 1 and 2 communications across both transmission and distribution (T&D) substations.

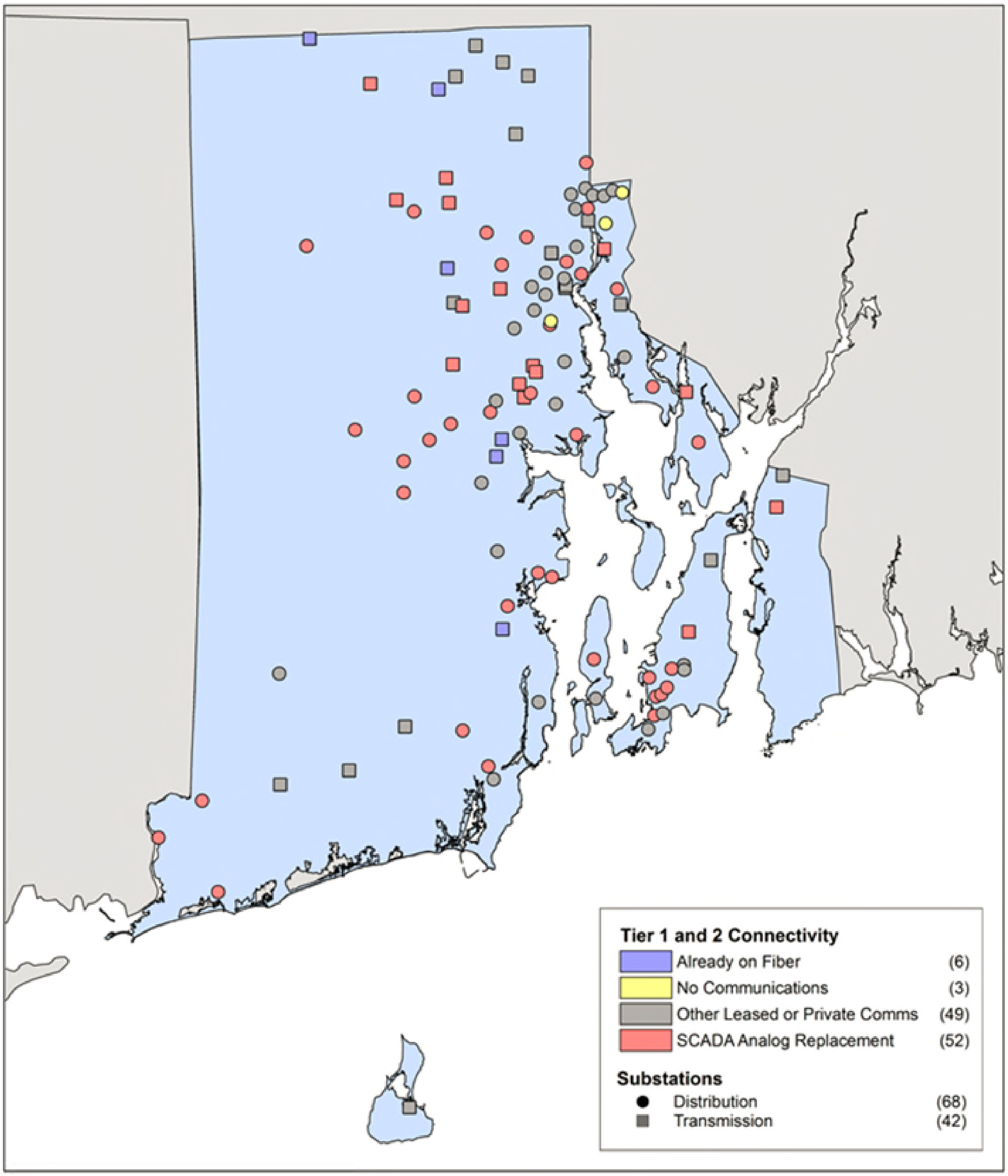


Figure 9.1: Tier 1 and 2 Network Connectivity

Tier 3 Modernization

Currently the Company utilizes a public cellular-based platform for connecting Advanced Field Devices such as VVO-controlled Advanced Regulators & Capacitors and Advanced (Line) Reclosers & Breakers with the control center SCADA system. This system is scaled as needed as new devices are commissioned.

As an alternative to the continued expansion of the existing cellular platform, the Company is evaluating options for a private FAN. The FAN would support data transport from the grid for Advanced Field Devices, VVO/CVR, and AMF. The Company envisions a hybrid approach of a public-private network where there will be some reliance on commercial cellular networks in rural areas. The high cost of serving a very limited number of field devices with a dedicated private network would not be financially feasible. A private network would only be built in rural areas where commercial coverage does not exist. In which case, satellite communications may be considered especially as newly deployed low-orbiting satellite constellations have introduced significantly improved network performance over traditional systems.

The Company has performed a nominal wireless design to estimate the number of radio sites required to cover a majority of grid field operations. The methodology of adding radio sites into the coverage design is driven by the density of the underlying field devices and nodes that require network connectivity now and in the future. The higher the device count per radio site, the more the benefits will outweigh the costs. Moreover, for each radio site, cost comparisons are also performed against an alternative cellular solution. A total of 42 sites across the state have been determined to provide approximately 76% private wireless coverage (817 of 1,075 square miles). The remaining 24% would be served by commercial cellular carriers. Tables 9.2 and 9,3 summarizes the total number of various existing infrastructure assets and devices that are expected to be covered by the new private network.

Table 9.2: Total Covered Area, Service Points and Utility Poles

County	Population	% Area Covered	Service Points		Utility Poles	
Bristol	49,875	92%	17,121	96%	12,846	97%
Kent	166,158	67%	56,718	96%	46,855	90%
Newport	82,888	92%	24,829	97%	32,266	96%
Providence	626,667	66%	165,430	96%	136,595	91%
Washington	126,979	84%	53,278	96%	63,616	94%
Totals	**1,052,567**		**317,376**		**292,178**	

Table 9.3: Total Covered Field Devices – Existing Reclosers and DER

County	Reclosers		DER*							
			Small		Medium		Large		Utility-Scale DG	
Bristol	20	95%	66	97%	6	100%				
Kent	70	97%	123	90%	14	100%	6	100%	12	100%
Newport	33	97%	118	58%	15	88%	6	100%	2	100%
Providence	200	90%	359	92%	57	98%	22	92%	34	92%
Washington	102	97%	228	95%	30	100%	15	100%	15	100%
Totals	**425**		**894**		**122**		**49**		**63**	

*Only commercial-scale DER

The 42-site nominal design is based on a coverage cell radius of 3 miles which was determined from both a network planning tool's typical single-site coverage and the Company's own experience of existing 700 MHz and 900 MHz radio site performance. In continuing to develop the network design for Rhode Island prior to GMP approval, real site locations will be identified and modeled using propagation tools to assess both coverage and capacity. The results simulated in these coverage studies would provide a high level of confidence (95% reliability) in predicting what field devices will be covered. This level of detail in preparing a network design is different than the high-level conceptual presentation of coverage shown in Figures 9.2 and 9.3 which simply represent a base station's 3-mile nominal coverage, which has not been engineered or modeled at this time.

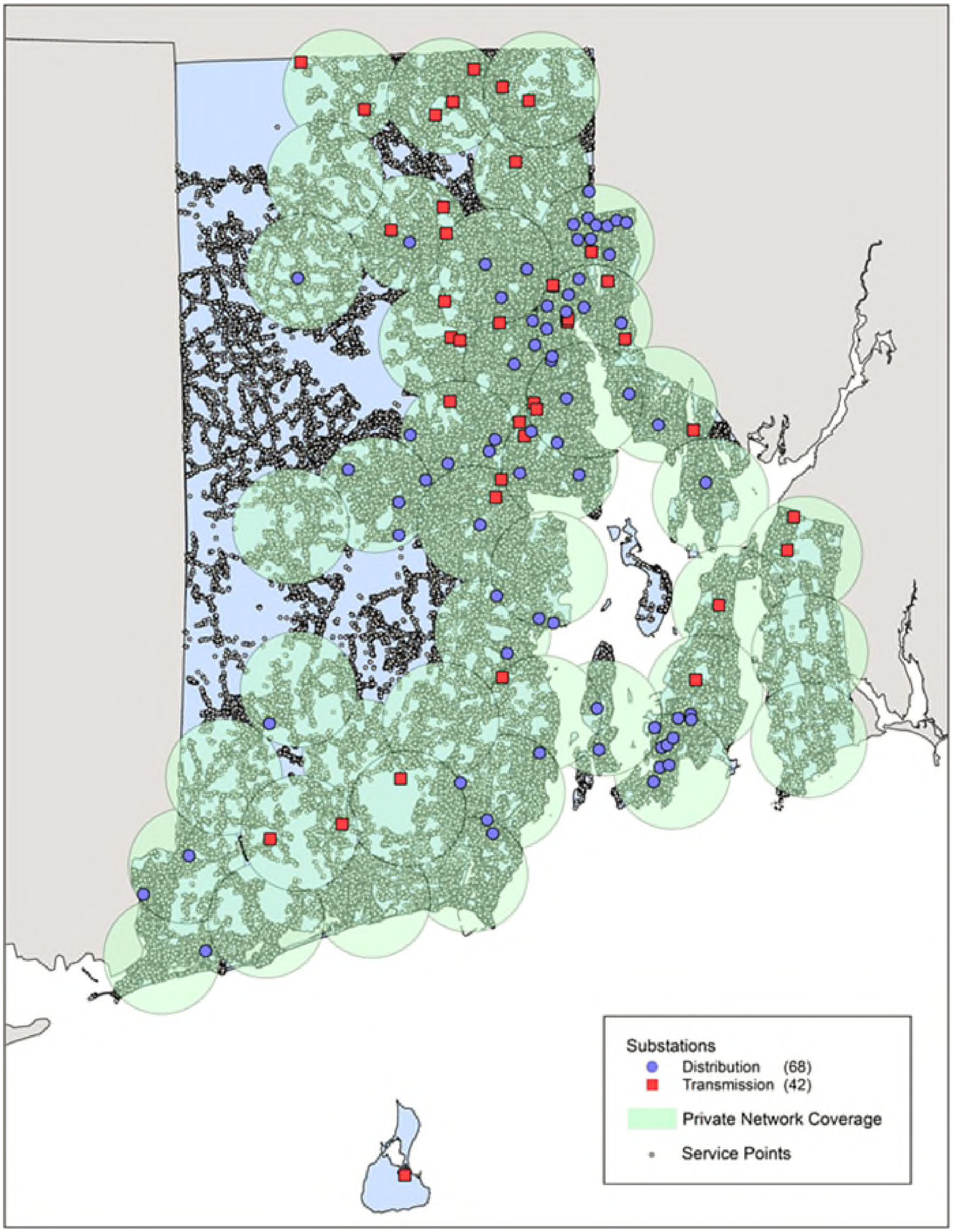


Figure 9.2: 42-Site Network Coverage Overlayed On Substation and Service Point Locations

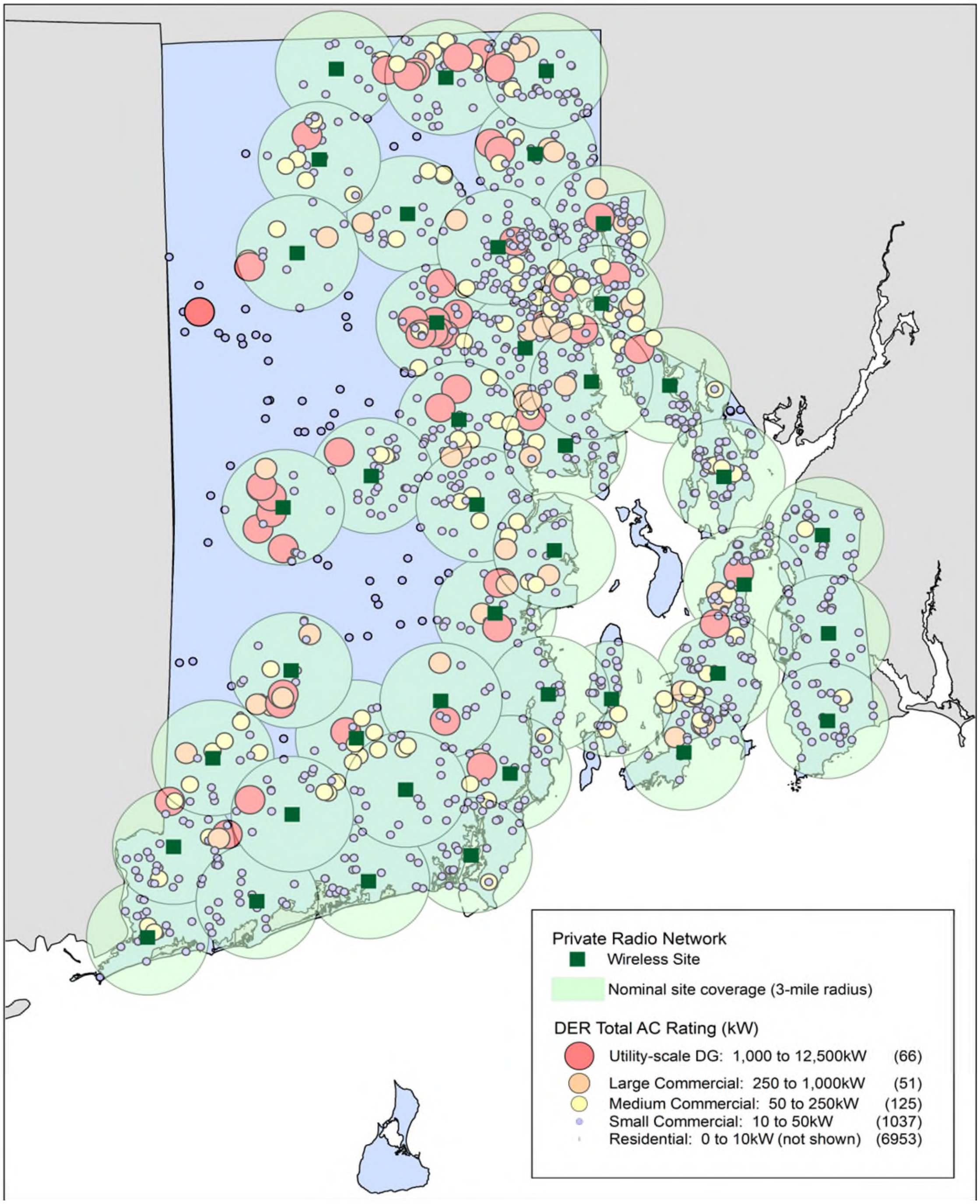


Figure 9.3: 42-Site Network Coverage Overlayed On DER Locations

The biggest challenge in building out a private wireless network is access to licensed spectrum. Most decisions related to viable network solutions and technology are driven by the cost of available spectrum. Utilities are competing for the same spectrum as the commercial carriers who have a business model that supports a spectrum cost in the hundreds of millions of dollars. There are however affordable options in the marketplace. The Company has evaluated several – many of the bands in the sub-1GHz range which are preferred due to their favorable far-reaching propagation which in turn greatly reduces site count and the associated cost of the network build and operation. The two options for spectrum acquisition are within the 700 MHz and 900 MHz bands. Both offer the opportunity to own the spectrum outright over leasing. At this time, the Company is not considering any leased or unlicensed spectrum for a private network. Rhode Island being one of the smallest states in population has an advantage when acquiring spectrum given the purchase price is determined by county population. This factor of demographics translates to a more affordable price for the State compared to states with higher overall population.

Once Tier 3 spectrum is identified, decisions on technology need to be vetted and evaluated. Factors of cost, performance, and ecosystem of product (radio site and edge device) are considered. Use cases are categorized and sorted into different levels of required network performance including throughput, latency, control, security, reliability, and device count. The technology choices currently available at the time for these bands often dictates what use cases can be considered for each. The Company divides the use cases into two groups: 1) mission-critical, low device count (10,000's) and 2) lower throughput, latency, and reliability coupled with high device count (100,000's to millions). While not completely finalized, the two leading technologies include Narrow-Band Highspeed for mission-critical communications and Narrow-Band-Internet of Things (IoT) for lower performance, higher device count. Narrow-Band Highspeed is a proprietary point-to-multipoint (PMP) technology that the Company currently uses in a limited number of locations in their service area. Narrow-Band-IoT is the same technology that follows the worldwide 3GPP standard that many commercial carriers have started to use; however, it would have to be rebanded to support the non-standard 700 MHz and 900 MHz frequencies.

10. Innovation and Technology Readiness Details

10.1 <u>Grid Modernization-Related Projects</u>

The Company and its affiliates, the Massachusetts Electric Company (MECO) and Niagara Mohawk Electric Company (NMPC), are involved in significant innovation and technology readiness projects related to grid modernization. Some of these projects are summarized in Table 10.1 below.

Table 10.1: Summary of Select ITR Pilot Projects at National Grid

Index #	Full Project Title	Grid Mod Category	Company	Status	Partners	Start Date	End Date
1	BNMC DSP Engagement Tool (aka DSP Demo Project)	FTM DERMS, Transactive Energy	NMPC	Completed	Buffalo Niagara Medical Campus, Opus One	2015	2019
2	Fruit Belt Neighborhood Solar	DG Integration, BTM DERMS	NMPC	Completed	City of Buffalo	2015	2019
3	Potsdam Community Resilience	Microgrid, FTM DERMS	NMPC	Completed	General Electric	2015	2019
4	Clifton Park Demand Reduction	AMF, TVR, DR, VVO/CVR	NMPC	In Progress		2016	Ongoing
5	Smart Home Rate	Smart Homes, BTM DERMS, DR	NMPC	In Progress		2016	Ongoing
6	Distributed Generation Interconnection	DG Integration	NMPC	Completed		2017	2019
7	Schenectady Smart City	Smart Cities, Public Comms	NMPC	In Progress	City of Schenectady	2018	Ongoing
8	Active Resource Integration (ARI) Project	DG Integration, FTM DERMS	NMPC	Proposed in 2020 Rate Case	MA & NY Solar Developers (TBD)	2021	TBD
9	DERMS Investigation	BTM & FTM DERMS	NMPC	Proposed in 2020 Rate Case		2022	TBD
10	Flexible Load Study	Advanced Demand Response	NMPC	Proposed in 2020 Rate Case		2021	TBD
11	Distributed Communications	FTM DERMS, DG Interconnection, Private Comms	NMPC	Proposed in 2020 Rate Case		2021	TBD
12	Syracuse Net-zero Carbon Building-to-Grid	BTM DERMS, Smart Buildings, DR	NMPC	Proposed in 2020 Rate Case	NYSERDA, Syracuse Housing Authority	2021	TBD
13	Energy Storage Value Stacking	FTM DERMS, Energy Storage, DR	NMPC	Proposed in 2020 Rate Case		2021	TBD

Index #	Full Project Title	Grid Mod Category	Company	Status	Partners	Start Date	End Date
14	Smart Inverter VVO/CVR Pilot	VVO/CVR, DG Integration, AMF	NMPC	Proposed in 2020 Rate Case	NYSERDA	2020	TBD
15	Solar Phase 2 & 3 Advanced PV Facilities	DG Integration, Energy Storage, FTM DERMS	MECO	Funded through Solar Phase 2 program	MA-TSRG, EPRI, Sandia National Labs,	2016	2022
16	The SunDial Framework	Energy Storage, BTM DERMS, DR	MECO	Funded through DoE FOA.	Fraunhofer	2016	2020
17	Optimal Distribution System Voltage Regulation using State Estimation and DER Grid-Support Functions	FTM DERMS	MECO	Funded through Solar Phase 2 program	Sandia National Labs	2017	2019
18	Solar Inverter Direct Load Control (ConnectedSolutions)	BTM DERMS, DR	NECO	Planned	Solar Inverter Manufacturers (SolarEdge, Enphase)	2021	Reviewed annually

Brief descriptions of each completed, in-progress, proposed, or planned project are summarized below:

1. BNMC DSP Engagement Tool (aka DSP Demo Project): Test Distribution System Platform (DSP) functionalities, coordinating and optimizing DERs using hourly price signals based on locational-based marginal pricing (i.e., LMP+D+E).

2. Fruit Belt Neighborhood Solar: Help low-to moderate-income customers access clean energy while reducing arrears through a neighborhood solar project in an economically distressed area, and test how solar can be paired with communications technologies to deliver benefits to the overall electricity system.

3. Potsdam Community Resilience: Fund a microgrid through a new tariff design, testing demand for a premium resiliency service. The work also includes new metering, billing, and financial services for DER providers.

4. Clifton Park Demand Reduction: Offer customers various programs and pricing signals to manage usage to reduce energy bills and demand during peak times.

5. Smart Home Rate: Leverage the offerings, tools, and price signals being provided in the Clifton Park DR Pilot, through additional technology that will enable customers to control appliances in their homes during times when electricity prices are high in order to reduce demand and create energy savings.

6. Distributed Generation Interconnection: Accelerate the pace and scale of interconnecting distributed generation systems above 50kW through upfront investment by the Company along with alternative cost allocation methodology.

7. Schenectady Smart City: Use street light infrastructure as a platform to deploy smart city technologies and services using connected devices and a low bandwidth wireless network. Three business models will be tested: Enhancing utility owned infrastructure, hybrid utility and smart city vendor shared infrastructure, and support city owned smart city infrastructure.

8. Active Resource Integration (ARI) Project: Test ability to increase the amount of solar DG integrated into the distribution system in constrained areas via development of curtailment capabilities and a DG-flexible load marketplace.

9. DERMS Investigation: Conduct a deep dive into many aspects of DERMS (e.g., use cases, functions, IT architecture, cybersecurity, BCA, vendor capabilities) to prepare National Grid for the enterprise-wide implementation of a DERMS platform and associated modules.

10. Flexible Load Study: Quantify ability of flexible load to solve potential peak load challenges from beneficial electrification and minimum load challenges from DG penetration simultaneously.

11. Distributed Communications: Investigate greater integration of DER into the grid via: 1) novel communication schemes and protocols through utilization of DTT and 3V0 low cost alternatives, 2) communications between the Company and the NYISO for new DER market products, 3) increased integration of DER into distribution automation schemes, 4) low-cost monitoring and control for smart inverters.

12. Syracuse Net-zero Carbon Building-to-Grid: Develop building-to-grid (“B2G”) software, communication, and integration to Building Management System (“BMS”) and DER to actively manage the increased electrical load to support the grid and potentially provide compensation to the building owner and tenants.

13. Energy Storage Value Stacking: Demonstrate the ability of two energy storage projects to dually participate in NYISO markets and support local grid reliability via novel software and associated controls including two new DLM programs (“Term DLM” and “Auto DLM”). These two programs offer new opportunities for load and energy storage to contribute to grid operations and Auto DLM will provide relief in targeted areas.

14. Smart Inverter VVO/CVR Pilot: Assess the feasibility and benefits of integrating smart inverters with the existing VVO/CVR scheme currently in operation in the Clifton Park DR Pilot. In addition, an offline analysis will be used to determine the incremental benefits of incorporating AMI data with optimal VVO/CVR operation.

15. Solar Phase 2 & 3 Advanced PV Facilities : Use advanced DER integration technologies (i.e., Smart Inverters, Energy Storage, Dynamic Var and Plant Controllers) to reduce system voltage and DER interconnection cost and time.

16. The SunDial Framework: Design, develop, and deploy a fully functional and integrated photovoltaic (PV), energy storage, and a facility load management system at the utility distribution scale. Capabilities to be demonstrated include: 1) Act as a dispatchable source of power generation; 2) Participate in current and future transactive energy markets; 3) Achieve an amortized lifetime cost that meets the DOE's 2020 target of $0.14/kWh levelized cost of electricity, and 4) Achieve a round-trip solar energy efficiency of at least 90%.

17. Optimal Distribution System Voltage Regulation using State Estimation and DER Grid-Support Functions: Develop and demonstrate a control system that measures power system parameters to estimate the status of a feeder, forecasts the distribution state over a short-term horizon, and issues optimal set point commands to DERs to regulate voltage and protect the system.

18. Solar Inverter Direct Load Control (ConnectedSolutions): Demonstrate advanced DR capabilities using autonomous Volt/Var functionality of customer's solar inverters to decrease the amount of power (kVA) that needs to be generated and distributed, increase the capacity on the grid for real current, decrease voltage fluctuations, and reduce energy loss. This capability will be added to the Company's existing ConnectedSolutions Bring-Your-Own-Device Program.

The Company plans to build off this significant work to help identify and evaluate GMP opportunities and enable the Company to implement grid modernization as quickly and cost-effectively as possible and provide the most value to customers. Details are presented in the Implementation Plan document.

10.2 Solar Phase 2 Smart Inverters

An important method to mitigate grid integration challenges due to proliferating DERs, is effective utilization of smart inverters. Smart inverters offer advanced grid-support capabilities like active and reactive power management to support voltage and frequency regulation, fault ride-through, and communication interoperability. A recent revision of DER interconnection standard IEEE 1547-2018 made grid-support capabilities mandatory for DER plants. Successful implementation and field demonstration of voltage regulation support functions including fixed power factor, volt-var, and automatic voltage regulation (AVR) are critical for wide-scale adoption of smart inverters and plant-level controllers. In 2017, the Company's Massachusetts affiliate and the Electric Power Research Institute (EPRI) began a collaborative multi-year research project to investigate and demonstrate potential benefits of smart inverters in real-world solar DG plants. These plants are installed and operated by National Grid as part of its Massachusetts's "Solar Phase 2 Program". A white paper was published that presents the results of the field-performance assessment and key findings from this demonstration project including:[22]

- Solar Phase 2 Program demonstrated successful implementation of advanced grid-support functions of DERs at the megawatt scale through a DER plant controller, which will enable larger-scale DER facilities to comply with IEEE 1547-2018 requirements.

- Fixed power factor, volt-var, and automatic voltage regulation (AVR) functions of DERs were implemented accurately by the plant controller at the five sites investigated in the project. When activated, these functions were able to bring the voltage closer to the target.

- Because DER plant controllers typically do not go through the same level of detailed certification testing as inverters, field verification of plants, especially during a commissioning process, is critically important to identify any unwanted behavior like the voltage oscillations observed at two sites.

- Power quality meters with high data resolution are valuable for larger DER plants to capture any voltage and/or power quality issues, which may not be visible through revenue meters.

11. Benefit Cost Analysis Details

11.1 Survey of BCA Approach for AMF and GMP Filings

To ensure that the Company had a comprehensive BCA that covered all the potential benefits and costs introduced by a grid modernization investment, the Company surveyed several other AMF and grid modernization plan utility filings to understand the scope of their BCAs (e.g., AMF only, GMP only) as well as the type of cost-effectiveness test that were being applied (e.g.,

[22] EPRI, *Field Performance Assessment of Advanced Grid Support Functions Implemented via Plant Controllers: National Grid Solar Phase II Program Report* (May 2020)

least-cost/best fit, societal cost test). This survey also provided a benchmark for benefit and cost categories to be included in the Company's GMP and AMF BCAs. The results of the survey are included in Table 11.1 and show that the scope and breadth of the Company's BCA for both AMF and GMP in Rhode Island are more thorough than most other recent filings in the survey as a result of the Company having applied the Docket 4600 Framework and detailed modeling of a future (2030) distribution system in Rhode Island.

Table 11.1: Comparison of Utility BCAs for AMF and GMP

Utility – State	AMF Only Least-Cost/ Best-Fit	GMP Only Least-Cost/ Best-Fit	AMF Only Quantitative BCA	GMP Only Quantitative BCA
Hawaiian Electric (HECO) – Hawaii	X	X		
Southern California Edison (SCE) – California		X		
Public Service Electric and Gas Company (PSE&G) – New Jersey			X	
Orange and Rockland (ORU) – New York			X	
Xcel Power – Minnesota			X	X
Duke Energy (DEC) – North Carolina			X	
Dominion Power – Virginia	X	X		
Dayton Power & Light (DP&L) – Ohio			X	X
National Grid – Massachusetts			X (combined AMF + GMP)	
National Grid – New York			X	X
National Grid – Rhode Island			X	X

Dayton Power and Light (DP&L) in Ohio can be considered a useful comparison for National Grid's BCA since DP&L also performed a full BCA in its AMF and GMP filings. DP&L filed its Distribution Modernization Plan with the PUC of Ohio in December 2018. The plan includes AMF, distribution automation (DA), ADMS, Smart Community demonstration projects, security upgrades, and EV infrastructure, among other investments. Figure 11.1 shows the benefits and costs estimated in their BCA.

Cost/Benefit Summary
(in Millions)

BENEFITS & COSTS	NOMINAL	NPV
BENEFITS *(20yr)*:	**$2,518.7**	**$1,350.6**
Utility	**$301.6**	**$136.3**
O&M Savings	$191.9	$83.4
Avoided Capital	$42.3	$20.9
Billing Process Efficiency	$67.5	$32.0
Customer	**$1,217.8**	**$478.6**
Energy & Demand Savings	$517.1	$194.3
Improved Reliability	$454.7	$196.3
Customer EV Savings	$246.0	$87.9
Societal Benefits	**$999.2**	**$735.8**
Reduced GHG	$53.7	$20.8
Economic Impact	$945.6	$714.9
COSTS *(20yr)*:	**$866.9**	**$577.4**
Capital	$575.8	$435.4
AFUDC	$9.9	$7.5
Cost of Existing Equipment	$20.2	$14.9
O&M	$261.0	$119.6
Net Benefit:	**$1,651.8**	**$773.2**
Benefit/Cost Ratio:	**2.9**	**2.3**

Figure 11.1: DP&L's Cost/Benefit Summary[23]

As shown in DP&L's summary, the Distribution Modernization Plan produced a benefit/cost ratio (BCR) of 2.3 based on a 20-year net present value (NPV). One item of note from DP&L's BCA is that the economic impact benefits account for a large portion of the overall net benefits. Partly for this reason, economic improvement benefits, such as job creation and other multiplier effects, are only included as a sensitivity analysis to National Grid's GMP BCA. The Company provides an economic improvement benefits discussion in Section 11.6: Economic Impact Analysis Details.

11.2 Mapping of Docket 4600 Benefit Categories to the GMP BCA

In its Report and Order in Docket No. 4600, the PUC held that the Docket No. 4600 Framework should serve as a starting point in making a business case for a proposal, but also that it should

[23] DP&L's Distribution Modernization Plan filing, December 2018, http://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=ee03c3a4-614c-4e89-a4e9-d9369ded51e2

not be the exclusive measure of whether a specific proposal should be approved.[24] The PUC recognized that there may be outside factors that need to be considered regardless of whether a specific proposal is determined to be cost-effective or not, such as statutory mandates or qualitative considerations, and that such application is consistent with the PUC's broad regulatory authority in setting just and reasonable rates.[25] The GMP BCA uses the Docket No. 4600 Framework to evaluate the cost-effectiveness of the proposed investment in the GMP.

Table 11.2 lists each category of the Docket 4600 Framework and indicates if each category is quantified in this GMP BCA. The manner in which categories either are factored into the BCA or omitted appears in the rightmost column. Benefit categories that have not been quantified for this business case may have been left to qualitative analysis for three reasons: 1) the category may not apply to the GMP investments; 2) the category may be difficult to accurately quantify at this time; or 3) the category may have a small enough impact that its quantification was deemed negligible. Consistent with the PUC's Docket No. 4600 Guidance Document, the impacts of qualified categories should be considered in the assessment of the business case. A more thorough description of unquantified categories appears in the more broadly scoped RI GMP Business Case.

[24] *See Investigation Into the Changing Electric Distrib. Sys. and the Modernization of Rates in Light of the Changing Distrib. Sys.*, Docket No. 4600, Report and Order No. 22851 at 23 (July 31, 2017).

[25] *See Id*.

Table 11.2: Benefit categories included in the Docket 4600 Framework and how they are included in the BCA model. For benefits that are excluded from the model, the table provides the reason for exclusion

	Benefit Category	Quantified in filing?	Treatment in GMP BCA Or reason for exclusion
Power Sector Level	Energy Supply & Transmission Operating Value of Energy Provided or Saved	Yes	Included in Reduced Customer Energy Use and Reduced DG Curtailment as Energy Spot Market Price Savings (excluding RGGI cost)
	REC Value	Yes	Included in Reduced Customer Energy Use and Reduced DG Curtailment
	Retail Supplier Risk Premium	Yes	8% supplier markup included in Reduced Customer Energy Use, Reduced DG Curtailment, and Reduced System Capacity Requirements benefit calculations
	Forward Commitment Capacity Value	Yes	Included in Reduced System Capacity Requirements as Generation Capacity Savings; assumes capacity market savings with 3-year lag
	Forward Commitment: Avoided Ancillary Services Value	No	Likely small impact
	Electric Transmission Capacity Value	Yes	Included in Reduced System Capacity Requirements as Transmission Capacity Savings
	Net Risk Benefits to Utility System Operations from DER Flexibility & Diversity	No	Likely small impact
	Option Value of Individual Resources	No	Difficult to accurately quantify at this time
	Investment Under Uncertainty: Real Options Value	No	Likely small impact
	Energy Demand Reduction Induced Price Effect (DRIPE)	Yes	Included in Reduced Customer Energy Use, Reduced DG Curtailment, and Reduced System Capacity Requirements as DRIPE Energy Benefit, Cross-DRIPE Benefit, and DRIPE Capacity Benefit. Intrastate DRIPE included, with ROP DRIPE impacts presented as a sensitivity only.
	GHG Compliance Costs	Yes	Included in Reduced Customer Energy Use and Reduced DG Curtailment as Embedded CO_2 Benefit (RGGI cost). RGGI costs disaggregated from market prices and included separately.
	Criteria Air Pollutant and Other Environmental Compliance Costs	No	Likely very small. Costs may be embedded in market prices but are not quantified or disaggregated.
	Innovation and Learning by Doing	No	Not applicable to GMP investments
	Distribution Capacity Costs	Yes	Included as avoided costs in Avoided D-system Infrastructure Costs and Avoided Legacy CAPEX Investments
	Distribution Delivery Costs	Yes	Included as avoided costs in OPEX Labor Efficiency and Avoided Legacy OPEX Investments
	Distribution System Performance	Yes	Benefits from conservation voltage reduction (VVO/CVR) and other performance improvements are included as Reduced Customer Energy Use, Reduced DG Curtailment, Reduced System Capacity Requirements, etc.
	Utility Low Income	Yes	Improvements in AMF-related bad-debt write-offs are calculated and shown in a sensitivity, but they are excluded from base RI Test as they are transfers between ratepayers
	Distribution System and Customer Reliability/Resilience Impacts	Yes	Included in Reduced Outage Restoration Time for GMP and Reduced Outage Notification Time (Societal Outage Management benefit) for AMF
	Distribution System Safety Loss/Gain	Yes	Included as Reduction in Damage Claims for AMF

	Benefit Category	Quantified in filing?	Treatment in GMP BCA Or reason for exclusion
Customer Level	Program Participant/Prosumer Benefits	No	Difficult to accurately quantify at this time due to the wide range of customer options and customer non-energy benefits related to uncertain potential customer actions in response to TVR
	Participant non-energy benefits: oil, gas, water, waste water	No	Not applicable to GMP investments. For example, incremental EV adoptions may result from improved ability to facilitate home charging but gasoline savings and vehicle incremental costs were excluded from the analysis to avoid double-counting with EV initiatives.
	Low-Income Participant Benefits	No	Likely small impact
	Consumer Empowerment & Choice	No	Difficult to accurately quantify at this time. Addressed qualitatively in the GMP.
	Non-participant Rate and Bill Impacts	Yes	Quantified at the aggregate utility level for AMF, but not included in RI Test
Societal Level	GHG Externality Cost	Yes	Included in Reduced Customer Energy Use (Societal Benefit) and Reduced DG Curtailment (Societal Benefit) as Non-embedded CO_2 Benefit (incremental to the GHG compliance cost) related to change in fossil fuel based wholesale power production and reduced "truck rolls" for AMR meter reading, etc.
	Criteria Air Pollutant and Other Environmental Externality Costs	Yes	Included in Reduced Customer Energy Use (Societal Benefit) and Reduced DG Curtailment (Societal Benefit) as Criteria Air Pollutant (NO_x) Benefit related to change in fossil fuel-based wholesale power production
	Conservation and Community Benefits	No	Likely small impact
	Non-energy benefits: Economic Development	Yes (sensitivity only)	Included as a sensitivity only. Potentially a large benefit, but relatively high uncertainty can discredit precision of other BCA components.
	Innovation and Knowledge Spillover (Related to demonstration projects and other RD&D)	No	Not applicable to most GMP investments. ITR Pilot project benefits will be evaluated when those projects are defined.
	Societal Low-Income Impacts	No	Difficult to accurately quantify at this time. Could be a large benefit for some households, but likely small for Rhode Island as a whole.
	Public Health	Yes	Included in Reduced Customer Energy Use (Societal Benefit) and Reduced DG Curtailment (Societal Benefit) as Public Health Benefit (SO_2) related to change in fossil fuel-based wholesale power production
	National Security and US International Influence	No	Likely small impact in foreseeable future due to US oil export balance

11.3 Docket No. 4600 and The Rhode Island Test

The cost-effectiveness test on which the Docket No. 4600 Framework is based, is known as the "Rhode Island Test." The Rhode Island Test considers benefits to the power system, the customer, and certain societal impacts. Because the Rhode Island Test is intended for evaluating a variety of programs, the Docket No. 4600 Framework includes a wide array of categories for consideration – some of which will be relevant depending on the proposal.[26] In this Section, the Company explains how it applies the Docket No. 4600 Framework for the purposes of the GMP Business Case.

The Docket No. 4600 Framework attempts to quantify whether the state of Rhode Island will be better off adopting a proposed program. The benefits assessed under the Docket No. 4600 Framework include operational utility benefits, customer benefits, reductions in resource requirements (e.g., transmission and distribution, generation capacity, and energy use) and reductions in externalities such as carbon emissions. Expenses borne by the utility or its customers appear as costs in the BCA. Transfers of money between the utility and its customers or between different customer groups are internal to this cost definition and therefore do not appear in the BCA

To capture the value of the GMP investments over time, the BCA considers an analysis timeframe of 20 years, which corresponds to the AMF solution lifetime including back-office system development. The Company believes this is appropriate given the time for meter installation and the manufacturers estimated meter life of 20 years. This is critical to understanding the full value of the GMP investments; while many costs appear in early years as AMF meters and Advanced Field Devices are installed and back-office systems are set up, benefits tend to accrue later as more customers benefit from energy savings, reliability improvements, and DER integration compared to the Reference Case.

Total benefits and costs are shown on an NPV basis using the 20-year term, end-of-period cash flows, and a discount rate equal to the Company's after-tax Weighted Average Cost of Capital (WACC) of 6.97%. Use of the WACC recognizes that many BCA elements are capital expenditures incurred or avoided by the Company and results in a more conservative analysis due to benefits accruing over the long term. The after-tax value is used because taxes are considered income transfers within the state and are therefore excluded. For the GMP and AMF filings, this calculation is also referred to as the Rhode Island Test.

The Company, with input from stakeholders in the PST Advisory Group, developed this approach based on the Docket No. 4600 Framework. During this engagement, some stakeholders indicated preferences for elements of the Rhode Island Test that were not aligned with the

[26] *See* Presentation of Staff Workshop on PUC's Docket 4600-A Guidance Document (November 1, 2018).

Company's approach. In the interest of capturing these differing opinions, the Company includes alternative BCA formulations in *Section 8.5.1: Alternative BCA Formulations* of the RI GMP Business Case showing how incorporating the proposed alternatives would affect the BCA.

11.4 Avoided DG Curtailment Benefit

Investments in grid modernization are expected to reduce renewable DG Curtailment in the High DER Scenario due to the ability of the system operator to optimize power output from renewable DG rather than relying on seasonal curtailment to maintain thermal and voltage compliance. The resulting customer and societal benefits have been estimated to quantify this benefit:

- Customer Benefits
  - Energy spot market price savings (excludes RGGI cost)
  - Embedded CO_2 benefit (RGGI cost)
  - DRIPE energy benefit
  - Cross-DRIPE benefit

- Societal Benefits
  - Non-embedded CO_2 benefit
  - Public health benefit (SO_2)
  - Criteria air pollutant benefit (NO_x)

The reduced curtailment compared to the Reference Case increases the amount of useable energy from the renewable DG and thereby reduces the need for energy procurement from other sources such as wholesale generators. This reduced need for generation procurement is valued at the avoided cost of wholesale generation, similar to how energy reductions from pricing programs are valued. For example:

*Energy Spot Market Price Savings = Reduced DG Curtailment MWh * Curtailment Wholesale Power Price*

Where: Curtailment Wholesale Power Price = average market price during the hours of reduced DG curtailment, which is assumed to be during future "off-peak" pricing periods (e.g., 8 am – 3 pm).

This valuation approach is consistent with the Synapse *Rhode Island Cost-Effectiveness Framework* in Docket 4600,[27] which specifically describes the power sector benefit of "Reduced

[27] Synapse, *Cost-Effectiveness Framework in Docket 4600* at 19 (October 29, 2018).

Energy Costs" as including "the energy avoided by the energy saved or generated by the DER" and also notes that "DERs can have very different operating profiles, and the avoided energy costs should reflect the hours in which the DER operated as closely as possible."

The reduced DG curtailment is specific to solar and on-shore wind installations, which generally have no operating costs for providing the increased energy output. In the Reference Case, which requires seasonal curtailment, it is assumed that, over time, DG providers would recover their full expected revenue (or bill savings) from the DG, regardless of the amount of curtailment. For example, the State's solar DG incentives may need to be increased, or policies changed in some way, to account for the curtailment revenue loss, assuming the State will continue to support clean energy policies that help achieve the Resilient RI Act or other State clean energy goals. The cost for such future incentives or other policies would likely be paid by ratepayers.[28]
For behind-the-meter (BTM) DG installations in the Grid Mod cases, there are incremental customer bill savings from the increased DG output due to avoiding seasonal curtailment, but the bill savings in excess of the wholesale power cost reductions are simple revenue transfers between participants (those with BTM DG) and non-participants. Such revenue transfers have no effect on the Benefit Cost Ratios (BCRs) of the Total Resource Cost (TRC) or Societal cost tests.

For front of-the-meter (FTM) DG installations (i.e., connected to the distribution system but not located behind the customer meter), there are not analogous revenue transfers and bill impacts for increased generation output, with the exception of programs such as Community Remote Net Metering, where participating customers get bill reductions as if their allocated share of a FTM DG were reducing the metered usage by the customer. However, as with the BTM case, the bill savings would not impact the TRC or Societal cost tests.

11.5 Economic Impact Analysis Details

The Docket No. 4600 Framework[29] includes consideration of societal economic development benefits and notes that such benefits can be reflected via a qualitative assessment or, alternatively, can be quantified through detailed economic modelling. Economic impacts were quantified using the Regional Economic Models, Inc. (REMI) model of the Rhode Island economy, which estimates the increased economic activity resulting from GMP investments. The overall societal impact is measured using the net Rhode Island gross domestic product (GDP),

[28] As an example, California ISO curtailments happen through a competitive market, where solar and wind plant operators are paid to ramp down production.
[29] *See Pub Util. Comm'n Guidance on Goals, Principles and values for Matters Involving the Narragansett Elec. Co. d/b/a National Grid,* Docket 4600-A (October 27, 2017).

which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms.
The Company and GMP and AMF Subcommittee members agree that economic development benefits are important. However, including these benefits in the base case BCA results can be problematic due to the relatively high uncertainty associated with these benefits related to GMP investments, which can discredit other components of the BCA. Additionally, because the benefits can be large, they create a "masking" effect. For these reasons, the GMP did not consider economic development benefits in its base case results but included it as a sensitivity. This section describes the economic impact modeling and efforts to limit uncertainty.

Methodology

Economic impacts were estimated using the REMI regional economic model of the Rhode Island economy. REMI has been used in the industry for over 30 years to estimate the economic development impact of various investments, programs and policy proposals. REMI has over 150 U.S. and international clients including the Rhode Island Department of Revenue; as well as other state, federal, and local government planning agencies; non-profit research organizations; energy consultants; universities; and utilities. National Grid leases a 169-sector version of REMI's Rhode Island model.

Only local spending was considered in the REMI analysis. Spending on materials to be purchased from outside of the region was not included as this will not have a significant impact on Rhode Island economic activity. Also, spending on specialized labor available only outside of Rhode Island was not included. Spending on local labor was allocated between general construction, electrical contractors and professional services before input to REMI. The REMI model estimates the proportion of this increase in Rhode Island demand that will be met locally versus from outside of Rhode Island. Net customer benefits were input into REMI as reduced electricity costs, allocated to residential and C&I customers based on load. REMI estimated the local economic impact of these electricity cost savings.

Brattle Group Study

The Brattle Group addressed Economic Impact Analysis uncertainty issues in a February 2019 report commissioned by the Company for the Rhode Island Energy Efficiency Resource Management Collaborative (EERMC).[30] In the report, Brattle recommended an approach to estimating the economic development benefits of EE investments that avoids double counting and overestimation. The approach involves estimating all economic impacts related to the investments, both positive and negative. For example, besides positive construction impacts of

[30] Mark Berkman & Jurgen Weiss, *Review of the RI Test and Proposed Methodology*, Prepared for National Grid by The Brattle Group (February 2019).

EE program spending, negative economic impacts should also be considered such as decreased T&D construction and power sector activity due to reduced peak demand.
Brattle also recommended an approach for identifying economic benefits and costs already included in the BCA so that they would not be counted twice. Finally, Brattle recommended using net Rhode Island GDP in the BCA to measure the societal impact of economic development benefits such as job years, incomes and the regional competitiveness of firms. The approach was accepted by the EERMC and is being used by the Company in the Rhode Island Test, the BCA model used to screen investments for Rhode Island's Energy Efficiency Program Plan (EEPP).

While the Company followed this same approach in estimating the economic development benefits of the proposed GMP investments, there is currently more uncertainty around the GMP benefits and costs than there is around the EEPP investments, including the timing of the GMP investments. For this reason, the Company includes the net GDP impacts along-side the BCA as a sensitivity but does not add them to the base case BCA results.

Overview of GMP Economic Development Benefits

Spending on GMP investments are expected to have net positive impacts on the Rhode Island economy. Tables 11.3 and 11.4 summarize these impacts, as well as the economic impacts that are not captured by the GMP BCA but should be considered. As can be seen, local GMP implementation spending, which excludes spending on equipment and specialized labor procured from outside of Rhode Island, has a $226-292 million positive impact on the State's GDP (20-year NPV) depending on DER adoption scenario. This is expected to add 2,937-3854 job years, $172-222 million in personal income (20-year NPV), and $13-17 million in state tax revenues (20-year NPV) to the Rhode Island economy due to increased demand for construction, engineering, project management, consulting, professional services and other industries involved in planning and implementing the GMP.

Over time, these economic gains are somewhat offset by reduced spending (e.g., T&D capacity spending, power sector spending, utility O&M spending) due to GMP investments. Net customer benefits, including electricity cost savings, is expected to add 3,448-7,857 job years, $324-1,064 million in personal income (20-year NPV), and $24-86 million in state tax revenues (20-year NPV) to the Rhode Island economy. Accounting for all these impacts, the GMP investments are expected to create a net of 4,744-8,560 job years, increase real personal income by $424-1,127 million (20-year NPV), raise state tax revenues by $39-98 million (20-year NPV), and increase GDP by $283-610 million (20-year NPV) in Rhode Island.

Table 11.3: GMP Economic Development Impacts. State of Rhode Island and BCA Consideration – Low DER Scenario

Full Grid Mod Case Economic Development Impacts – Low DER Scenario	Job Years*	Personal Income (20-year NPV, $M)	State Tax Revenue (20-year NPV, $M)	GDP (20-year NPV, $M)
Local GMP Implementation Spending	2,937	$ 172	$ 13	$ 226
Reduced T&D Capacity Spending	(1,072)	$ (53)	$ (4)	$ (71)
Avoided Utility O&M Spending	(679)	$ (27)	$ 6	$ (40)
Reduced Power Sector Spending	110	$ 8	$ 0	$ 0
Net Customer Benefits (After Costs)	3,448	$ 324	$ 24	$ 169
Net State of Rhode Island	**4,744**	**$ 424**	**$ 39**	**$ 283**
Net for BCA Consideration	4,390	$ 393	$ 36	$ 266

Table 11.4: GMP Project Economic Development Impacts. State of Rhode Island and BCA Consideration – High DER Scenario

Full Grid Mod Case Economic Development Impacts – High DER Scenario	Job Years*	Personal Income (20-year NPV, $M)	State Tax Revenue (20-year NPV, $M)	GDP (20-year NPV, $M)
Local GMP Implementation Spending	3,854	$ 222	$ 17	$ 292
Reduced T&D Capacity Spending	(2,407)	$ (131)	$ (10)	$ (172)
Avoided Utility O&M Spending	(856)	$ (37)	$ 5	$ (63)
Reduced Power Sector Spending	110	$ 8	$ 0	$ 0
Net Customer Benefits (After Costs)	7,857	$ 1,064	$ 86	$ 553
Net State of Rhode Island	**8,560**	**$ 1,127**	**$ 98**	**$ 610**
Net for BCA Consideration	7,731	$ 1,021	$ 89	$ 553

* A "job year" is one job for a period of one year. Job year losses associated with reduced Utility O&M spending include eliminated meter reader positions and their indirect and induced employment impacts.

BCA Consideration

Some of the net economic development benefits to Rhode Island shown in Tables 11.3 and 11.4 are already captured in the GMP BCA. Specifically, the direct economic impact of net customer benefits, which are reduced electricity costs to residential and C&I customers, are included. However, the secondary impacts of these cost reductions, known as indirect and induced impacts, are not included in the BCA but should be considered. For residential customers, these impacts consist of increased supply chain and service sector activity as customers spend a portion of their electricity cost savings locally. For C&I customers, this includes positive local supply chain and output effects as firms increase production due to lower electricity costs. On the other hand, the total (direct, indirect and induced) economic impact of GMP implementation and other net benefits (e.g., reduced meter reading, T&D capacity, power sector spending) are not currently included in the BCA. The final rows of Tables 11.3 and 11.4 add these economic impacts together plus the indirect and induced impact of net customer benefits. The overall societal impact is measured by net GDP, which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms. This has a 20-year NPV of $266-553 million depending on DER adoption scenario and is considered alongside the BCA as a sensitivity.

11.6 Estimated Annual Costs

Table 11.5: Grid Mod Only Case Cost Estimates – Low DER Scenario

Grid Mod Only Cost Estimate - Low DER Scenario, $ million (nominal)	Yr 1 FY 2022	Yr 2 FY 2023	Yr 3 FY 2024	Yr 4 FY 2025	Yr 5 FY 2026	Yr 6 FY 2027	Yr 7 FY 2028	Yr 8 FY 2029	Yr 9 FY 2030	Yr 10 FY 2031
System Data Portal	$ 0.72	$ 0.74	$ 0.76	$ 0.79	$ 0.81	$ 0.84	$ 0.86	$ 0.89	$ 0.91	$ 0.94
Feeder Monitoring Sensors	$ 0.08	$ 0.35	$ 0.65	$ 0.94	$ 1.24	$ 1.55	$ 1.86	$ 2.18	$ 2.50	$ 2.67
Advanced Capacitors & Regulators	$ 0.39	$ 1.19	$ 2.15	$ 3.08	$ 4.03	$ 4.99	$ 5.98	$ 6.98	$ 7.98	$ 8.46
Advanced Reclosers & Breakers	$ 0.14	$ 0.61	$ 1.23	$ 2.18	$ 3.15	$ 4.13	$ 5.12	$ 6.13	$ 7.15	$ 8.18
GIS Data Enhancements	$ 1.18	$ 1.35	$ 1.09	$ 0.70	$ 0.62	$ 0.63	$ 0.65	$ 0.66	$ 1.60	$ 1.45
ADMS Core Functionality	$ 5.27	$ 4.90	$ 4.73	$ 1.97	$ 1.01	$ 1.04	$ 1.07	$ 1.02	$ 4.01	$ 1.16
Protection & Arc flash App (ADMS)	$ -	$ -	$ -	$ 0.01	$ 0.08	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09
Underlying IT Infrastructure	$ 1.79	$ 1.09	$ 1.03	$ 0.52	$ 0.49	$ 0.46	$ 0.47	$ 0.48	$ 0.54	$ 0.55
Appropriate Cyber Services	$ 0.85	$ 0.33	$ 0.15	$ 0.16	$ 0.16	$ 0.17	$ 0.48	$ 1.11	$ 0.38	$ 0.19
Network Management	$ 1.49	$ 1.57	$ 1.15	$ 1.29	$ 0.67	$ 0.69	$ 0.71	$ 0.73	$ 2.80	$ 1.47
OpTel Strategy	$ 10.36	$ 11.15	$ 7.98	$ 2.56	$ 2.67	$ 2.79	$ 2.91	$ 3.04	$ 3.17	$ 3.31
Existing VVO/CVR Platform	$ 0.86	$ 1.55	$ 1.74	$ 0.39	$ 0.40	$ 0.41	$ -	$ -	$ -	$ -
VVO/CVR App (ADMS)	$ -	$ -	$ 0.01	$ 0.08	$ 0.08	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09
FLISR App (ADMS)	$ -	$ -	$ -	$ 0.00	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.09
DERMS	$ -	$ 2.11	$ 2.16	$ 2.22	$ 2.59	$ 0.31	$ 0.32	$ 0.33	$ 0.34	$ 0.34
ITR Pilot Projects	$ -	$ 1.05	$ 1.08	$ 1.11	$ 1.13	$ 1.16	$ 1.19	$ -	$ -	$ -
Total	**$ 23.12**	**$ 27.99**	**$ 25.92**	**$ 18.01**	**$ 19.23**	**$ 19.42**	**$ 21.88**	**$ 23.80**	**$ 31.65**	**$ 29.00**

Grid Mod Only Cost Estimate - Low DER Scenario, $ million (nominal)	Yr 11 FY 2032	Yr 12 FY 2033	Yr 13 FY 2034	Yr 14 FY 2035	Yr 15 FY 2036	Yr 16 FY 2037	Yr 17 FY 2038	Yr 18 FY 2039	Yr 19 FY 2040	Yr 20 FY 2041	20-Year FY22-41
System Data Portal	$ 0.97	$ 1.00	$ 1.03	$ 1.06	$ 1.09	$ 1.12	$ 1.16	$ 1.19	$ 1.23	$ 1.26	**$ 19.37**
Feeder Monitoring Sensors	$ 2.50	$ 2.48	$ 2.47	$ 2.45	$ 2.44	$ 2.42	$ 2.41	$ 2.40	$ 2.39	$ 2.38	**$ 38.35**
Advanced Capacitors & Regulators	$ 7.80	$ 7.71	$ 7.63	$ 7.56	$ 7.49	$ 7.42	$ 7.35	$ 7.29	$ 7.23	$ 7.17	**$ 119.87**
Advanced Reclosers & Breakers	$ 8.05	$ 7.96	$ 7.88	$ 7.80	$ 7.72	$ 7.65	$ 7.58	$ 7.52	$ 7.46	$ 7.40	**$ 115.05**
GIS Data Enhancements	$ 0.71	$ 0.72	$ 0.74	$ 0.76	$ 0.77	$ 1.88	$ 1.71	$ 0.83	$ 0.84	$ 0.86	**$ 19.75**
ADMS Core Functionality	$ 1.19	$ 1.22	$ 1.26	$ 1.30	$ 1.34	$ 4.79	$ 1.42	$ 1.46	$ 1.51	$ 1.55	**$ 43.21**
Protection & Arc flash App (ADMS)	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.02	**$ 0.68**
Underlying IT Infrastructure	$ 0.56	$ 0.57	$ 0.59	$ 0.71	$ 0.73	$ 0.74	$ 0.76	$ 0.78	$ 1.04	$ 1.07	**$ 14.97**
Appropriate Cyber Services	$ 0.19	$ 0.20	$ 0.20	$ 0.56	$ 1.25	$ 0.44	$ 0.23	$ 0.24	$ 0.24	$ 0.25	**$ 7.77**
Network Management	$ 0.80	$ 0.83	$ 0.85	$ 0.88	$ 4.55	$ 2.17	$ 0.96	$ 0.99	$ 1.02	$ 1.05	**$ 26.67**
OpTel Strategy	$ 1.37	$ 1.40	$ 1.43	$ 1.46	$ 7.56	$ 1.53	$ 1.56	$ 1.60	$ 1.64	$ 1.67	**$ 71.16**
Existing VVO/CVR Platform	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 5.36**
VVO/CVR App (ADMS)	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.02	**$ 0.76**
FLISR App (ADMS)	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.01	**$ 0.53**
DERMS	$ 0.35	$ 0.36	$ 0.37	$ 0.38	$ 0.38	$ 0.39	$ 0.40	$ 0.41	$ 0.42	$ 0.43	**$ 14.62**
ITR Pilot Projects	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 6.73**
Total	**$ 24.52**	**$ 24.49**	**$ 24.47**	**$ 24.94**	**$ 35.36**	**$ 30.60**	**$ 25.58**	**$ 24.73**	**$ 25.05**	**$ 25.13**	**$ 504.86**

Table 11.6: Grid Mod Only Case Cost Estimates – High DER Scenario

Grid Mod Only Cost Estimate - High DER Scenario, $ million	Yr 1 FY 2022	Yr 2 FY 2023	Yr 3 FY 2024	Yr 4 FY 2025	Yr 5 FY 2026	Yr 6 FY 2027	Yr 7 FY 2028	Yr 8 FY 2029	Yr 9 FY 2030	Yr 10 FY 2031	Yr 11 FY 2032	Yr 12 FY 2033	Yr 13 FY 2034	Yr 14 FY 2035	Yr 15 FY 2036	Yr 16 FY 2037	Yr 17 FY 2038	Yr 18 FY 2039	Yr 19 FY 2040	Yr 20 FY 2041	20-Year FY22-41
System Data Portal	$ 0.72	$ 0.74	$ 0.76	$ 0.79	$ 0.81	$ 0.84	$ 0.86	$ 0.89	$ 0.91	$ 0.94	$ 0.97	$ 1.00	$ 1.03	$ 1.06	$ 1.09	$ 1.12	$ 1.16	$ 1.19	$ 1.23	$ 1.26	**$ 19.37**
Feeder Monitoring Sensors	$ 0.07	$ 0.56	$ 1.11	$ 1.64	$ 2.18	$ 2.73	$ 3.29	$ 3.86	$ 4.44	$ 4.75	$ 4.45	$ 4.42	$ 4.39	$ 4.36	$ 4.33	$ 4.31	$ 4.29	$ 4.27	$ 4.25	$ 4.23	**$ 67.92**
Advanced Capacitors & Regulators	$ 0.37	$ 1.91	$ 3.65	$ 5.33	$ 7.05	$ 8.78	$ 10.55	$ 12.35	$ 14.17	$ 15.03	$ 13.83	$ 13.69	$ 13.54	$ 13.41	$ 13.28	$ 13.15	$ 13.03	$ 12.92	$ 12.81	$ 12.70	**$211.56**
Advanced Reclosers & Breakers	$ 0.14	$ 0.98	$ 2.01	$ 3.74	$ 5.48	$ 7.25	$ 9.03	$ 10.85	$ 12.70	$ 14.57	$ 14.32	$ 14.17	$ 14.03	$ 13.88	$ 13.75	$ 13.63	$ 13.50	$ 13.39	$ 13.28	$ 13.18	**$203.89**
GIS Data Enhancements	$ 1.18	$ 1.35	$ 1.09	$ 0.70	$ 0.62	$ 0.63	$ 0.65	$ 0.66	$ 1.60	$ 1.45	$ 0.71	$ 0.72	$ 0.74	$ 0.76	$ 0.77	$ 1.88	$ 1.71	$ 0.83	$ 0.84	$ 0.86	**$ 19.75**
ADMS Core functionality	$ 4.79	$ 4.40	$ 4.53	$ 1.76	$ 0.79	$ 0.81	$ 0.83	$ 0.78	$ 3.77	$ 0.91	$ 0.94	$ 0.96	$ 0.99	$ 1.03	$ 1.06	$ 4.51	$ 1.12	$ 1.16	$ 1.20	$ 1.24	**$ 37.57**
Protection & Arc flash app (ADMS)	$ -	$ -	$ -	$ 0.01	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.15	$ 0.16	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.02	**$ 1.05**
Underlying IT infrastructure	$ 2.26	$ 1.59	$ 1.24	$ 0.74	$ 0.72	$ 0.68	$ 0.70	$ 0.72	$ 0.78	$ 0.80	$ 0.82	$ 0.84	$ 0.85	$ 0.98	$ 1.01	$ 1.03	$ 1.05	$ 1.08	$ 1.35	$ 1.38	**$ 20.61**
Appropriate Cyber Services	$ 0.85	$ 0.33	$ 0.15	$ 0.16	$ 0.16	$ 0.17	$ 0.48	$ 1.11	$ 0.38	$ 0.19	$ 0.19	$ 0.20	$ 0.20	$ 0.56	$ 1.25	$ 0.44	$ 0.23	$ 0.24	$ 0.24	$ 0.25	**$ 7.77**
Network Management	$ 1.49	$ 1.57	$ 1.15	$ 1.29	$ 0.67	$ 0.69	$ 0.71	$ 0.73	$ 2.80	$ 1.47	$ 0.80	$ 0.83	$ 0.85	$ 0.88	$ 4.55	$ 2.17	$ 0.96	$ 0.99	$ 1.02	$ 1.05	**$ 26.67**
OpTel Strategy	$ 10.36	$ 11.15	$ 7.98	$ 2.56	$ 2.67	$ 2.79	$ 2.91	$ 3.04	$ 3.17	$ 3.31	$ 1.37	$ 1.40	$ 1.43	$ 1.46	$ 7.56	$ 1.53	$ 1.56	$ 1.60	$ 1.64	$ 1.67	**$ 71.16**
Existing VVO/CVR Platform	$ 0.86	$ 2.74	$ 3.09	$ 0.69	$ 0.70	$ 0.72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 8.80**
ADMS Integrated VVO	$ -	$ -	$ 0.01	$ 0.14	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.15	$ 0.16	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ 0.02	**$ 1.19**
FLISR App (ADMS)	$ -	$ -	$ -	$ 0.00	$ 0.13	$ 0.14	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.01	**$ 0.90**
DERMS	$ -	$ 2.11	$ 2.16	$ 2.22	$ 2.59	$ 0.31	$ 0.32	$ 0.33	$ 0.34	$ 0.34	$ 0.35	$ 0.36	$ 0.37	$ 0.38	$ 0.38	$ 0.39	$ 0.40	$ 0.41	$ 0.42	$ 0.43	**$ 14.62**
ITR Pilot Projects	$ -	$ 1.05	$ 1.08	$ 1.11	$ 1.13	$ 1.16	$ 1.19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 6.73**
Total	**$ 23.10**	**$ 30.48**	**$ 30.01**	**$ 22.86**	**$ 25.99**	**$ 27.99**	**$ 31.97**	**$ 35.76**	**$ 45.52**	**$ 44.23**	**$ 38.78**	**$ 38.60**	**$ 38.45**	**$ 38.78**	**$ 49.08**	**$ 44.20**	**$ 39.06**	**$ 38.10**	**$ 38.32**	**$ 38.29**	**$719.57**

11.7 Estimated Annual Benefits

Table 11.7: Grid Mod Only Case Benefit Estimates – Low DER Scenario

Grid Mod Only Benefit Estimate - Low DER Scenario, $ million (nominal)			Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	20-Year
			FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034	FY 2035	FY 2036	FY 2037	FY 2038	FY 2039	FY 2040	FY 2041	FY22-41
Avoided O&M Costs	OPEX Labor Efficiency	GIS network model savings	$ -	$ -	$ -	$ 0.84	$ 0.87	$ 0.90	$ 0.92	$ 0.95	$ 0.98	$ 1.01	$ 1.04	$ 1.07	$ 1.10	$ 1.13	$ 1.17	$ 1.20	$ 1.24	$ 1.28	$ 1.32	$ 1.35	**$ 18.37**
		Maintenance response savings (NRAs)	$ -	$ 0.00	$ 0.01	$ 0.03	$ 0.04	$ 0.05	$ 0.07	$ 0.08	$ 0.10	$ 0.11	$ 0.13	$ 0.13	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.16	$ 0.16	$ 0.17	$ 0.17	**$ 1.99**
	Avoided Legacy OPEX Investments	Field device RTB telecoms savings (existing)	$ -	$ -	$ -	$ 0.09	$ 0.11	$ 0.13	$ 0.13	$ 0.13	$ 0.14	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.15	$ 0.16	$ 0.16	$ 0.16	$ 0.17	$ 0.17	$ 0.17	**$ 2.46**
		DER RTB telecoms savings	$ -	$ -	$ -	$ -	$ -	$ 0.01	$ 0.03	$ 0.04	$ 0.06	$ 0.07	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	**$ 1.07**
Avoided Capital Costs	Avoided Legacy CAPEX Investments	Stand-alone OMS license savings	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	**$ 1.58**
		Stand-alone VVO/CVR license savings (existing)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.30	$ 0.30	$ 0.31	$ 0.32	$ 0.33	$ 0.33	$ 0.34	$ 0.35	$ 0.36	$ 0.36	$ 0.37	$ 0.38	$ 0.39	$ 0.40	**$ 4.85**
		DS0 to T1 telecoms savings	$ -	$ 1.15	$ 1.76	$ 1.44	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4.36**
	Avoided D-System Infrastructure Cost (Load Optimization)	Ratepayer infrastructure savings (Small DG)	$ -	$ -	$ -	$ 1.72	$ 1.38	$ 1.67	$ 1.66	$ 1.65	$ 1.75	$ 1.80	$ 1.83	$ 1.81	$ 1.79	$ 1.78	$ 1.76	$ 1.74	$ 1.72	$ 1.70	$ 1.68	$ 1.66	**$ 29.09**
		Ratepayer RTB savings (Large DG)	$ -	$ -	$ 0.23	$ 0.47	$ 0.88	$ 1.31	$ 1.76	$ 2.21	$ 2.68	$ 3.17	$ 3.39	$ 3.62	$ 3.65	$ 3.68	$ 3.71	$ 3.74	$ 3.76	$ 3.78	$ 3.80	$ 3.83	**$ 49.68**
		Developer infrastructure savings (Large DG)	$ -	$ -	$ 5.00	$ 5.14	$ 5.28	$ 5.42	$ 5.56	$ 5.71	$ 5.86	$ 5.25	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	$ 0.19	**$ 45.07**
Customer Benefits	Reduced Customer Energy Use (VVO/CVR)	Energy spot market price savings (excluding RGGI cost)	$ -	$ 0.38	$ 1.09	$ 1.86	$ 2.62	$ 3.30	$ 3.99	$ 5.27	$ 5.71	$ 6.68	$ 7.89	$ 8.29	$ 8.20	$ 8.59	$ 8.91	$ 9.25	$ 9.60	$ 9.97	$ 10.35	$ 10.75	**$ 122.70**
		Embedded CO2 benefit (RGGI cost)	$ -	$ 0.03	$ 0.09	$ 0.16	$ 0.24	$ 0.33	$ 0.43	$ 0.53	$ 0.67	$ 0.82	$ 0.98	$ 1.00	$ 1.02	$ 1.05	$ 1.07	$ 1.09	$ 1.12	$ 1.14	$ 1.17	$ 1.20	**$ 14.14**
		DRIPE energy benefit	$ -	$ 0.01	$ 0.05	$ 0.10	$ 0.15	$ 0.20	$ 0.24	$ 0.27	$ 0.30	$ 0.32	$ 0.33	$ 0.31	$ 0.27	$ 0.21	$ 0.16	$ 0.11	$ 0.07	$ 0.04	$ 0.04	$ 0.02	**$ 3.21**
		Cross-DRIPE benefit	$ -	$ 0.01	$ 0.03	$ 0.05	$ 0.07	$ 0.09	$ 0.11	$ 0.12	$ 0.12	$ 0.13	$ 0.14	$ 0.12	$ 0.10	$ 0.08	$ 0.05	$ 0.03	$ 0.02	$ 0.01	$ 0.01	$ 0.01	**$ 1.29**
	Reduced System Capacity Requirements (VVO/CVR)	Transmission capacity savings	$ -	$ 0.18	$ 0.49	$ 0.81	$ 1.15	$ 1.50	$ 1.86	$ 2.23	$ 2.62	$ 3.03	$ 3.44	$ 3.51	$ 3.58	$ 3.66	$ 3.73	$ 3.80	$ 3.88	$ 3.96	$ 4.04	$ 4.12	**$ 51.58**
		Generation capacity savings	$ -	$ -	$ -	$ -	$ 0.16	$ 0.44	$ 0.73	$ 1.04	$ 1.39	$ 1.71	$ 2.06	$ 2.48	$ 2.85	$ 3.26	$ 3.34	$ 3.43	$ 3.52	$ 3.62	$ 3.71	$ 3.81	**$ 37.57**
		DRIPE capacity benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.00	$ 0.05	$ 0.13	$ 0.24	$ 0.36	$ 0.46	$ 0.53	$ 0.58	$ 0.61	$ 0.63	$ 0.64	$ 0.56	$ 0.56	$ 0.46	**$ 5.81**
	Reduced Outage Restoration Time	FLISR value of reliability improvement	$ -	$ -	$ -	$ -	$ -	$ 8.34	$ 9.44	$ 10.59	$ 11.79	$ 13.03	$ 14.33	$ 14.65	$ 14.98	$ 15.32	$ 15.67	$ 16.02	$ 16.38	$ 16.75	$ 17.13	$ 17.52	**$ 211.95**
		Reclosers value of reliability improvement	$ -	$ 0.11	$ 0.41	$ 0.79	$ 1.19	$ 1.60	$ 2.03	$ 2.48	$ 2.95	$ 3.44	$ 3.95	$ 4.04	$ 4.13	$ 4.23	$ 4.32	$ 4.42	$ 4.52	$ 4.62	$ 4.73	$ 4.83	**$ 58.80**
		SOM value of reliability improvement	$ -	$ -	$ 0.08	$ 0.23	$ 0.39	$ 0.61	$ 0.56	$ 0.44	$ 0.38	$ 0.23	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.15	$ 0.16	$ 0.16	$ 0.16	$ 0.17	$ 0.17	**$ 4.47**
	Reduced DG Curtailment (ADMS/DERMS)	Energy spot market price savings (excluding RGGI cost)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
		Embedded CO2 benefit (RGGI cost)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
		DRIPE energy benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
		Cross-DRIPE benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Societal Benefits	Reduced Customer Energy Use (VVO/CVR)	Non-embedded CO2 benefit	$ -	$ 0.23	$ 0.61	$ 1.00	$ 1.41	$ 1.83	$ 2.26	$ 2.71	$ 3.15	$ 3.60	$ 4.07	$ 4.16	$ 4.25	$ 4.35	$ 4.45	$ 4.55	$ 4.65	$ 4.75	$ 4.86	$ 4.97	**$ 61.87**
		Public health benefit (SO2)	$ -	$ 0.03	$ 0.09	$ 0.15	$ 0.22	$ 0.29	$ 0.37	$ 0.45	$ 0.54	$ 0.62	$ 0.71	$ 0.72	$ 0.74	$ 0.76	$ 0.78	$ 0.79	$ 0.81	$ 0.83	$ 0.85	$ 0.87	**$ 10.61**
		Criteria air pollutant benefit (NOx)	$ -	$ 0.01	$ 0.02	$ 0.03	$ 0.05	$ 0.07	$ 0.08	$ 0.10	$ 0.12	$ 0.14	$ 0.16	$ 0.16	$ 0.17	$ 0.17	$ 0.17	$ 0.18	$ 0.18	$ 0.19	$ 0.19	$ 0.20	**$ 2.40**
	Reduced DG Curtailment (ADMS/DERMS)	Non-embedded CO2 benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
		Public health benefit (SO2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
		Criteria air pollutant benefit (NOx)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total			**$ -**	**$ 2.14**	**$ 9.97**	**$ 14.99**	**$ 16.29**	**$ 28.17**	**$ 32.60**	**$ 37.44**	**$ 41.83**	**$ 45.95**	**$ 45.77**	**$ 47.53**	**$ 48.51**	**$ 49.99**	**$ 51.08**	**$ 52.20**	**$ 53.35**	**$ 54.47**	**$ 55.72**	**$ 56.90**	**$ 744.90**

Table 11.8: Grid Mod Only Case Benefit Estimates – High DER Scenario

Grid Mod Only Benefit Estimate - High DER Scenario, $ million (nominal)			Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	20-Year
			FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034	FY 2035	FY 2036	FY 2037	FY 2038	FY 2039	FY 2040	FY 2041	FY22-41
Avoided O&M Costs	OPEX Labor Efficiency	GIS network model savings	$ -	$ -	$ -	$ 0.84	$ 0.87	$ 0.90	$ 0.92	$ 0.95	$ 0.98	$ 1.01	$ 1.04	$ 1.07	$ 1.10	$ 1.13	$ 1.17	$ 1.20	$ 1.24	$ 1.28	$ 1.32	$ 1.35	**$ 18.37**
		Maintenance response savings (NRAs)	$ -	$ 0.00	$ 0.01	$ 0.03	$ 0.04	$ 0.05	$ 0.07	$ 0.08	$ 0.10	$ 0.11	$ 0.13	$ 0.13	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.16	$ 0.16	$ 0.17	$ 0.17	**$ 1.98**
	Avoided Legacy OPEX Investments	Field device RTB telecoms savings (existing)	$ -	$ -	$ -	$ 0.09	$ 0.11	$ 0.13	$ 0.13	$ 0.13	$ 0.14	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.15	$ 0.16	$ 0.16	$ 0.16	$ 0.17	$ 0.17	$ 0.17	**$ 2.46**
		DER RTB telecoms savings	$ -	$ -	$ -	$ -	$ -	$ 0.31	$ 0.63	$ 0.97	$ 1.32	$ 1.69	$ 1.73	$ 1.77	$ 1.81	$ 1.85	$ 1.89	$ 1.93	$ 1.98	$ 2.02	$ 2.07	$ 2.11	**$ 24.06**
Avoided Capital Costs	Avoided Legacy CAPEX Investments	Stand-alone OMS license savings	$ -	$ -	$ -	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	**$ 1.58**
		Stand-alone VVO/CVR license savings (existing)	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.30	$ 0.30	$ 0.31	$ 0.32	$ 0.33	$ 0.33	$ 0.34	$ 0.35	$ 0.36	$ 0.36	$ 0.37	$ 0.38	$ 0.39	$ 0.40	**$ 4.85**
		DS0 to T1 telecoms savings	$ -	$ 1.15	$ 1.76	$ 1.44	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 4.36**
	Avoided D-System Infrastructure Cost (Load Optimization)	Ratepayer infrastructure savings (Small DG)	$ -	$ -	$ -	$ 6.18	$ 4.86	$ 5.93	$ 5.88	$ 5.83	$ 6.12	$ 6.24	$ 6.31	$ 6.25	$ 6.19	$ 6.13	$ 6.07	$ 6.00	$ 5.94	$ 5.87	$ 5.79	$ 5.72	**$ 101.30**
		Ratepayer RTB savings (Large DG)	$ -	$ -	$ 0.81	$ 1.65	$ 3.11	$ 4.62	$ 6.18	$ 7.79	$ 9.44	$ 11.15	$ 11.94	$ 12.74	$ 12.85	$ 12.96	$ 13.06	$ 13.16	$ 13.24	$ 13.31	$ 13.38	$ 13.48	**$ 174.88**
		Developer infrastructure savings (Large DG)	$ -	$ -	$ 17.61	$ 18.04	$ 18.48	$ 18.93	$ 19.39	$ 19.86	$ 20.33	$ 18.14	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	**$ 153.44**
Customer Benefits	Reduced Customer Energy Use (VVO/CVR)	Energy spot market price savings (excluding RGGI cost)	$ -	$ 0.37	$ 1.60	$ 2.93	$ 4.26	$ 5.47	$ 6.67	$ 8.88	$ 9.67	$ 11.38	$ 13.47	$ 14.16	$ 14.01	$ 14.67	$ 15.23	$ 15.80	$ 16.41	$ 17.03	$ 17.69	$ 18.36	**$ 208.06**
		Embedded CO2 benefit (RGGI cost)	$ -	$ 0.03	$ 0.14	$ 0.26	$ 0.39	$ 0.55	$ 0.72	$ 0.90	$ 1.13	$ 1.39	$ 1.67	$ 1.71	$ 1.75	$ 1.79	$ 1.83	$ 1.87	$ 1.91	$ 1.95	$ 2.00	$ 2.04	**$ 24.02**
		DRIPE energy benefit	$ -	$ 0.01	$ 0.07	$ 0.15	$ 0.24	$ 0.33	$ 0.40	$ 0.47	$ 0.52	$ 0.56	$ 0.58	$ 0.55	$ 0.47	$ 0.38	$ 0.28	$ 0.19	$ 0.13	$ 0.07	$ 0.07	$ 0.03	**$ 5.49**
		Cross-DRIPE benefit	$ -	$ 0.01	$ 0.04	$ 0.08	$ 0.12	$ 0.15	$ 0.18	$ 0.20	$ 0.22	$ 0.23	$ 0.24	$ 0.21	$ 0.17	$ 0.13	$ 0.09	$ 0.06	$ 0.04	$ 0.03	$ 0.02	$ 0.01	**$ 2.22**
	Reduced System Capacity Requirements (VVO/CVR)	Transmission capacity savings	$ -	$ 0.18	$ 0.72	$ 1.28	$ 1.87	$ 2.47	$ 3.11	$ 3.76	$ 4.44	$ 5.15	$ 5.88	$ 6.00	$ 6.12	$ 6.24	$ 6.37	$ 6.50	$ 6.63	$ 6.76	$ 6.89	$ 7.03	**$ 87.41**
		Generation capacity savings	$ -	$ -	$ -	$ -	$ 0.16	$ 0.65	$ 1.15	$ 1.69	$ 2.29	$ 2.86	$ 3.48	$ 4.21	$ 4.85	$ 5.56	$ 5.71	$ 5.86	$ 6.02	$ 6.18	$ 6.34	$ 6.51	**$ 63.53**
		DRIPE capacity benefit	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.00	$ 0.05	$ 0.19	$ 0.37	$ 0.58	$ 0.77	$ 0.91	$ 1.00	$ 1.06	$ 1.10	$ 1.12	$ 0.99	$ 0.99	$ 0.81	**$ 9.94**
	Reduced Outage Restoration Time	FLISR value of reliability improvement	$ -	$ -	$ -	$ -	$ -	$ 11.20	$ 13.10	$ 15.08	$ 17.14	$ 19.29	$ 21.52	$ 22.01	$ 22.51	$ 23.02	$ 23.54	$ 24.07	$ 24.61	$ 25.17	$ 25.74	$ 26.32	**$ 314.32**
		Reclosers value of reliability improvement	$ -	$ 0.11	$ 0.70	$ 1.38	$ 2.09	$ 2.84	$ 3.62	$ 4.43	$ 5.27	$ 6.15	$ 7.07	$ 7.23	$ 7.39	$ 7.56	$ 7.73	$ 7.91	$ 8.09	$ 8.27	$ 8.46	$ 8.65	**$ 104.94**
		SOM value of reliability improvement	$ -	$ -	$ 0.07	$ 0.16	$ 0.27	$ 0.40	$ 0.36	$ 0.27	$ 0.23	$ 0.14	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.09	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	**$ 2.84**
	Reduced DG Curtailment (ADMS/DERMS)	Energy spot market price savings (excluding RGGI cost)	$ -	$ -	$ -	$ 1.82	$ 5.64	$ 10.00	$ 15.27	$ 25.15	$ 29.83	$ 30.67	$ 32.30	$ 32.88	$ 31.50	$ 34.38	$ 35.45	$ 36.56	$ 37.70	$ 38.88	$ 40.10	$ 41.36	**$ 479.48**
		Embedded CO2 benefit (RGGI cost)	$ -	$ -	$ -	$ 0.16	$ 0.52	$ 1.00	$ 1.75	$ 2.61	$ 3.45	$ 3.73	$ 4.00	$ 4.09	$ 4.19	$ 4.28	$ 4.38	$ 4.48	$ 4.58	$ 4.68	$ 4.79	$ 4.90	**$ 57.58**
		DRIPE energy benefit	$ -	$ -	$ -	$ 0.06	$ 0.21	$ 0.46	$ 0.79	$ 1.18	$ 1.51	$ 1.60	$ 1.48	$ 1.26	$ 0.99	$ 0.74	$ 0.48	$ 0.27	$ 0.11	$ 0.04	$ -	$ -	**$ 11.17**
		Cross-DRIPE benefit	$ -	$ -	$ -	$ 0.03	$ 0.11	$ 0.23	$ 0.39	$ 0.56	$ 0.69	$ 0.68	$ 0.58	$ 0.45	$ 0.31	$ 0.21	$ 0.13	$ 0.07	$ 0.04	$ 0.02	$ 0.02	$ 0.02	**$ 4.55**
Societal Benefits	Reduced Customer Energy Use (VVO/CVR)	Non-embedded CO2 benefit	$ -	$ 0.22	$ 0.89	$ 1.58	$ 2.30	$ 3.03	$ 3.79	$ 4.57	$ 5.34	$ 6.13	$ 6.95	$ 7.10	$ 7.26	$ 7.43	$ 7.60	$ 7.77	$ 7.94	$ 8.12	$ 8.31	$ 8.49	**$ 104.82**
		Public health benefit (SO2)	$ -	$ 0.03	$ 0.13	$ 0.24	$ 0.35	$ 0.48	$ 0.61	$ 0.76	$ 0.91	$ 1.06	$ 1.21	$ 1.24	$ 1.27	$ 1.29	$ 1.32	$ 1.35	$ 1.38	$ 1.42	$ 1.45	$ 1.48	**$ 17.99**
		Criteria air pollutant benefit (NOx)	$ -	$ 0.01	$ 0.03	$ 0.05	$ 0.08	$ 0.11	$ 0.14	$ 0.17	$ 0.21	$ 0.24	$ 0.27	$ 0.28	$ 0.29	$ 0.29	$ 0.30	$ 0.31	$ 0.31	$ 0.32	$ 0.33	$ 0.33	**$ 4.06**
	Reduced DG Curtailment (ADMS/DERMS)	Non-embedded CO2 benefit	$ -	$ -	$ -	$ 0.98	$ 3.03	$ 5.55	$ 9.24	$ 13.23	$ 16.29	$ 16.46	$ 16.64	$ 17.02	$ 17.40	$ 17.80	$ 18.20	$ 18.61	$ 19.03	$ 19.46	$ 19.90	$ 20.35	**$ 249.22**
		Public health benefit (SO2)	$ -	$ -	$ -	$ 0.11	$ 0.35	$ 0.66	$ 1.13	$ 1.66	$ 2.10	$ 2.15	$ 2.19	$ 2.24	$ 2.29	$ 2.35	$ 2.40	$ 2.45	$ 2.51	$ 2.57	$ 2.62	$ 2.68	**$ 32.47**
		Criteria air pollutant benefit (NOx)	$ -	$ -	$ -	$ 0.03	$ 0.10	$ 0.19	$ 0.33	$ 0.48	$ 0.60	$ 0.62	$ 0.63	$ 0.64	$ 0.66	$ 0.67	$ 0.69	$ 0.70	$ 0.72	$ 0.74	$ 0.75	$ 0.77	**$ 9.33**
Total			**$ -**	**$ 2.12**	**$ 24.57**	**$ 39.66**	**$ 49.65**	**$ 76.71**	**$ 96.32**	**$122.09**	**$140.87**	**$149.73**	**$142.81**	**$146.95**	**$147.37**	**$152.96**	**$156.08**	**$159.36**	**$162.82**	**$166.35**	**$170.22**	**$174.05**	**$2,280.69**

12. Endnotes

[i] California Working Group, Overview of Discussions Q3 2014 thru Q1 2015 Volume 2, More Than Smart-Caltech, 2015.

[ii] New York Market Design and Platform Technology Working Group , *Report of the Market Design and Platform Technology Working Group* 55, 56 (August 2015).

[iii] Dirkman, John, *Best Practices for Creating Your Smart Grid Network Model, Schneider Electric*, http://cdn.iotwf.com/resources/8/Best-practices-for-creating-your-Smart-Grid-network-model_2013.pdf

[iv] Department of Energy, NETL, *The Modern Grid Strategy – A Vision for the Smart Grid* 9 (June 2009), https://www.netl.doe.gov/File%20Library/research/energy%20efficiency/smart%20grid/whitepapers/Whitepaper_The-Modern-Grid-Vision_APPROVED_2009_06_18.pdf

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[vii] Definition developed from the following resources:

a. Department of Energy. “Quadrennial Technology Review – An Assessment of Energy Technologies and Research Opportunities, Chapter 3, Section 3E”. Page 11, September 2015.
b. New York Market Design and Platform Technology Working Group (MDPT). “Report of the Market Design and Platform Technology Working Group”, Pages 100-101, August 2015.

[viii] Collier, Steven, *What Is An Outage Management System and How Can It Help Me?*, APPA Academy webinar (April 2012).

[ix] Definition developed from the following resources:

a. De Martini, Paul and Kristov, Lorenzo, “Distribution Systems in a High Distributed Energy Resources Future – Planning, Market Design, Operation and Oversight”, Page 53, October 2015.
b. Southern California Edison, “Grid Modernization Distribution System Concept of Operations, Version 1.0”, Page 8, January 2016.
c. Schneider Electric, “Preparing for Distributed Energy Resources”, Page 8, May 2012. Available online: http://www2.schneider-electric.com/documents/support/white-papers/electric-utilities/998-2095-05-29-12_preparing-for-distributed-energy-resources.pdf

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GMP BCA Model

GMP BCA Model

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The Company provided the GMP BCA Model as an Excel file

As permitted by the Public Utilities Commission Rule 810-RICR-00-00-1-1.3(H)(3) and Rhode Island Gen. Laws § 38-2-2(4)(A), -(B), the Company is seeking confidential treatment of the GMP BCA Model Excel file